Decision 2003-106

EUB

# Direct Energy Regulated Services

## Electric Regulated Rate Tariff and Gas Default Rate Tariff

December 18, 2003

Alberta Energy and Utilities Board

Decision 2003-106

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**ALBERTA ENERGY AND UTILITIES BOARD**
Decision 2003-106: Direct Energy Regulated Services
Electric Regulated Rate Tariff and Gas Default Rate Tariff
Application No. 1302109

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**ALBERTA ENERGY AND UTILITIES BOARD**
**Calgary Alberta**

**DIRECT ENERGY REGULATED SERVICES**
**ELECTRIC REGULATED RATE TARIFF AND**
**GAS DEFAULT RATE TARIFF**

**Decision 2003-106**
**Application No. 1302109**
**File No. 6405-20-1**

## 1 INTRODUCTION AND BACKGROUND

Direct Energy Regulated Services (DERS) submitted an application (the Application) to the Alberta Energy and Utilities Board (the Board or EUB) on May 20, 2003, seeking approval of gas Default Rate Tariffs (DRT) and electricity Regulated Rate Tariffs (RRT) for two test periods.

In a letter to interested parties dated May 26, 2003, the Board noted the interrelated nature of the Application with two other matters: the ATCO Retail Sale Application (the Retail Sale Application) and the ATCO Gas 2003 Gas Rate Unbundling Application (the Unbundling Application). The Retail Sale Application and the Unbundling Application were filed on April 28, 2003 and June 6, 2003 respectively.

Notice with respect to this hearing was e-mailed on June 10, 2003, to all parties on the mailing list for the ATCO Electric Ltd. (ATCO Electric) 2003/2005 General Tariff (GTA), the ATCO Gas North, ATCO Gas South (ATCO Gas) 2003/2004 General Rate Application (GRA), the Retail Sale Application, the ATCO Electric 2003 Regulated Rate Option Tariff Application and to the interested parties for the ATCO Gas Cost Recovery Rates (GCRR). Notice was also published in most daily newspapers in Alberta on June 12, 2003. A list of parties who appeared at the hearing is included in Appendix 1.

As part of the Retail Sale Application, ATCO Gas / ATCO Electric sought approval for the transfer of certain gas and electric assets and of arrangements with DERS to perform the functions of the default supply provider (DSP) under the *Default Gas Supply Regulation*, AR 184/2003 (*DGS Regulation*) in the ATCO Gas service territory and to perform the functions of the owner under the *Regulated Default Supply Regulation*, AR 168/2003, as amended (*RDS Regulation*) in the ATCO Electric service territory. (The forgoing elements of the Retail Sale Application, which require Board approval, are herein referred to as the Retail Sale). Even though these approvals were not yet granted, DERS submitted the Application for the DRT and RRT.

In a letter to interested parties dated June 13, 2003, the Board stated that it would deal with the Retail Sale Application and the Application jointly in order to maximize efficiency of time and process. The Board indicated that it would allow sharing of information between the records of the two applications, thereby creating a so-called "rolling record." The Board emphasized that the proposed process did not prejudice the Board's consideration of matters with respect to the Application or the Retail Sale Application. The Board noted that the risk of proceeding with the Application, before a determination was made on the Retail Sale Application, rested solely with DERS. The Board also noted that the Retail Sale hearing would be completed before commencement of the DERS hearing. The Board also established dates for the filing of information requests and responses in the Unbundling Application so that they would be received prior to the filing of intervener evidence in the other two proceedings. The Board noted that this portion of the Unbundling Application would also be included in the "rolling record" of the Retail Sale Application and the Application. The balance of the Unbundling Application would continue on a separate timeline from the other two applications.

ATCO Gas submitted the Unbundling Application on the assumption that the Retail Sale Application would be approved and, accordingly, ATCO Gas would effectively become a pipes-only utility. Therefore, ATCO Gas submitted that it would no longer provide certain functions that would be provided by the DSP, being DERS, or retailers. The main objectives of the Unbundling Application were to identify the impacts resulting from ATCO Gas ceasing to provide the gas supply and customer care functions and to develop new interim rates effective with the approval of the Retail Sale Application.

The initial process schedule for the Application was also outlined in the June 13, 2003 letter from the Board as follows:

| | |
|---|---|
| Information Requests to Applicant | July 7, 2003 |
| Information Responses from Applicant | July 16, 2003 |
| Intervener Evidence | July 28, 2003 |
| Information Requests to Interveners | August 12, 2003 |
| Responses from Interveners | August 26, 2003 |
| Rebuttal Evidence (from Applicant) | September 8, 2003 |

The Board panel assigned to this application was comprised of Mr. B. T. McManus, Q.C. (Presiding Member), Mr. J. I. Douglas, FCA, Member and Mr. W. K. Taylor, Acting Member.

The Board considered the Application at a public hearing held in Calgary from September 17, 2003 to October 1, 2003. Written Argument and Reply were submitted on October 11, 2003 and October 17, 2003 respectively. Accordingly, for purposes of this Decision, the Board considers that the record closed on October 18, 2003.

The Board issued Decision 2003-098[1] on December 4, 2003 approving the Retail Sale Application.

In this Decision, the Board will make a determination on interim non-energy rates for the DRT and RRT with final rates pending the submission of a benchmarking study on customer care costs.[2] In addition, a refiling will be required from DERS, no later than December 29, 2003 (the Refiling), for its proposed Default Rate Service Terms and Conditions (DRS T&C) and its proposed Regulated Rate Service Terms and Conditions (RRS T&C). In addition, the Board will direct DERS to follow the ATCO Gas process for filing its monthly Gas Cost Flow-Through

---

[1] Decision 2003-098 – ATCO Electric Ltd., ATCO Gas North and ATCO Gas South, Both Operating Divisions of ATCO Gas and Pipelines Ltd., Transfer of Certain Retail Assets to Direct Energy Marketing Limited and Proposed Arrangements with Direct Energy Regulated Services to Perform Certain Regulated Retail Functions, dated December 4, 2003

[2] The non-energy rates and revenue requirements for the DRT and RRT are shown in Appendix 4 and 5 respectively. The spreadsheets used to calculate the rates are included in Appendix 9 and 10. The associated Rate Schedules for the North and South DRT are included in Appendix 6 and 7 and Appendix 8 includes the RRT Rate Schedules.

Rate (GCFR) and therefore, the Board would expect DERS to file a proposed January 2004 GCFR with the Board on December 24, 2003.

Having heard the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons respecting the Application.

# 2 GENERAL

## 2.1 Legislation and Jurisdiction

In 2003, new regulations came into force under the *Electric Utilities Act*, S.A. 2003, c.E-5.1 (EUA) and the *Gas Utilities Act*, R.S.A. 2000, c.G-5 as amended by the *Gas Utilities Amendment Act*, 2003, S.A. 2003, c. 5 (GUA). The *DGS Regulation* and *RDS Regulation* have a direct linkage to the Application and the other regulations listed below are somewhat related to the Application.

### 2.1.1 Gas

The other relevant legislation affecting natural gas for purposes of this Decision includes:

- The GUA
- *Natural Gas Billing Regulation*, AR 185/2003
- *Roles, Relationships and Responsibilities Regulation*, AR 186/2003 (*Gas RRR Regulation*)
- *Code of Conduct Regulation*, AR 183/2003 under the GUA (*Gas Code Regulation*)

Pursuant to section 28.1(5) of the GUA, a gas distributor must provide gas services to customers pursuant to a DRT.

A gas distributor, or a person authorized by a gas distributor, who provides gas services to customers pursuant to a DRT is defined by section 28 of the GUA to be a "default supply provider".

Section 4(1)(m) of the *Gas RRR Regulation* provides that a gas distributor must act as a DSP to customers who pay a default rate for gas.

Also, section 2(1) of the *Gas RRR Regulation* also provides:

> 2(1) Subject to section 28.1(2) of the Act, a gas distributor may authorize other persons to perform any or all of the functions of the gas distributor under this Regulation.

Sections 2 and 3 of the *DGS Regulation* provide:

> 2. Subject to section 28.1(2) of the Act, a gas distributor may, with the approval of the Board, authorize a person to act as default supply provider in the gas distributor's service area in accordance with this Regulation.

> 3(1) A default supply provider must prepare a default rate tariff for the purpose of recovering the prudent costs and expenses of providing gas services to customers.
>
> (2) The default supply provider must apply to the Board for approval of its default rate tariff.
>
> (3) The default supply provider may recover in its default rate tariff its prudent billing costs of
>
> (a) gas distribution tariff billing for the default rate tariff, and
> (b) billing to customers for the default rate tariff, including taxes and municipal charges.
>
> (4) An application for approval of a default rate tariff must
>
> (a) include the terms and conditions under which the default supply provider proposes to offer gas services, and
> (b) state how the following information will each be shown separately in the tariff and on customer's bills:
>
> (i) the gas charge, shown as a dollar amount per gigajoule;
> (ii) the administrative charge, which may include a billing charge, shown as a dollar amount for each period specified in the tariff;
> (iii) the delivery charge for gas distribution service, shown as a fixed delivery charge and a variable delivery charge;
> (iv) rate riders, if applicable;
> (v) franchise fees, if applicable;
> (vi) any other fees or amounts prescribed by the Board.
>
> (5) The gas charge under subsection (4)(b)(i) must be calculated on a monthly flow through basis, as determined by the Board.

Section 5 of the *DGS Regulation* outlines what the Board must consider when reviewing an application for approval of a DRT.

> 5 When considering an application for approval of a default rate tariff, the Board must:
>
> (a) have regard for the principle that a default rate tariff must provide the default supply provider with a reasonable opportunity to recover the prudent costs and expenses incurred by the default supply provider and a reasonable return on costs deemed eligible by the Board, excluding the cost of gas that is provided and delivered, and
>
> (b) examine the reasonableness of the default supply provider's billing costs, and other costs the Board considers appropriate in the prevailing circumstances, without regard to any overall increase in costs due to the separation of gas distribution service and the provision of gas services.

The Board also notes that the *Natural Gas Billing Regulation* has a provision corresponding to section 5(b) above relating to a gas distributor's application for approval of its gas distribution tariff.[3]

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[3] Section 10 in the Natural Gas Billing Regulation

Section 8 of the *DGS Regulation* notes that a DSP may authorize other persons to perform any or all of the functions of the DSP under this Regulation.

### 2.1.2 Electric

The other relevant legislation affecting electricity for purposes of this Decision includes:

- *Electric Utilities Act*, S.A. 2003, c. E-5.1 (EUA)
- *Distribution Tariff Regulation*, AR 162/2003 (*DT Regulation*)
- *Roles, Relationships and Responsibilities Regulation*, AR 169/2003 under the EUA (*Electric RRR Regulation*)
- *Code of Conduct Regulation*, AR 160/2003 under the EUA (*Electric Code Regulation*)

The legislation governing the Board's jurisdiction to consider and determine an RRT application is similar to that governing the DRT. The Board's jurisdiction to consider and determine the RRT application arises out of certain provisions of the EUA and the *RDS Regulation*.

Pursuant to section 103 of the EUA, each owner of an electric distribution system must prepare an RRT for the purpose of recovering the prudent costs of providing electricity services to eligible customers and must apply to the Board for approval of such tariff.

Pursuant to section 104 of the EUA:

> 104 (1) An owner of an electric distribution system may make arrangements under which other persons perform any or all of the duties or functions of the owner under this Act, and the regulations.
>
> (2) No arrangement under subsection (1) affects or reduces the responsibility or liability of the owner to carry out those duties or functions.

Section 7 of the *RDS Regulation* requires each owner to make available to eligible customers in its service area the option of purchasing electricity services pursuant to the RRT.

Section 11 of the same regulation provides:

> 11. An arrangement made by an owner under section 104 of the Act under which another person is authorized to perform any or all of the duties or functions of the owner under this Regulation has no effect unless the arrangement is approved by the owner's regulatory authority.

In the EUA, the regulated rate provider (RRP) is defined as the owner of an electric distribution system, or a person authorized by the owner that provides electricity services to eligible customers in the owner's service area under an RRT.

Recent amendments[4] (the Amendments) to the *RDS Regulation* have amended the definition of "transition rate" to mean:

---

[4] Alberta Regulations 323/2003 and 344/2003

> (i) the charge for electric energy payable under a regulated rate tariff approved by the Board or other regulatory authority under the *Electric Utilities Act*, SA 2000 c.E-5 where the charge includes arrangements to manage the financial risk associated with electric energy supply and does not flow-through the power pool price, or

The Amendments have also changed the time period during which a transition rate is to be provided to Eligible Customers.

Section 2 of the *RDS Regulation* provides in part:

> 2(1) As part of an application for approval of a regulated rate tariff under section 103 of the Act,
>
> (a) an owner must, subject to subsections (1.2) and (1.3), on January 1, 2004 and during the period up to and including June 30, 2006, provide only a transition rate for all eligible customers, and
>
> (b) an owner must, on and after July 1, 2006, provide only a flow-through rate for all eligible customers.
>
> (1.2) A regulatory authority may extend the January 1, 2004 date specified in subsection (1)(a) of this section and in section 3(2) and (3)(a) in respect of an application for approval of a regulated rate tariff made to the regulatory authority under section 103 of the Act.
>
> (1.3) An extension made by a regulatory authority under subsection (1.2) must not extend beyond July 1, 2004.

The effect of the Amendments is to require the RRP to offer a hedged regulated default rate tariff product to all eligible customers until July 1, 2006. The hearing into the Application concluded prior to the Amendments being promulgated and therefore the requested relief does not reflect the changes effected by the Amendments. Accordingly, the Board has continued to deal with the Application as filed.

The Amendments allow the Board to extend compliance with the new provisions by DERS until July 1, 2004. The Board notes that on December 8, 2003, DERS filed an application requesting that the Board grant an extension of the date for the implementation of a transition rate in the ATCO Electric service territory as contemplated in the Amendments to the *RDS Regulation*. The Board also notes that DERS indicated that if the Board granted the extension, it would immediately file for approval to enter into negotiated settlement discussions with interested parties on this matter. The Board in this Decision will grant the requested extension and in order to bring the terms and conditions of the RRT approved by this Decision into compliance with the *RDS Regulation* as amended, the Board directs DERS to file an application on or prior to February 15, 2004 if it appears that the settlement process will not be successful. Otherwise, DERS is directed to file its negotiated settlement application by March 31, 2004.

In the context of the Application, DERS has proposed a flow-through rate for Rate Classification Customers and Eligible Customers. The definition of Rate Classification Customers and Eligible Customers is shown below.

| Rate Classification Customer | Eligible Customer |
|---|---|
| • a residential rate classification customer,<br>• a farm rate classification customer, or<br>• an irrigation rate classification customer,<br>• as defined in a regulated rate tariff. | • a Rate Classification Customer, and<br>• any other customer, if the owner's reasonable forecast of the customer's annual consumption of electric energy at a site is less than 250 megawatt hours of electric energy at that site; |

An owner is defined in the *RDS Regulation* to include the owner of the electric distribution system and one or more persons who performs any or all of the duties or functions of the owner through an arrangement.

Subsection 2(3) of the *RDS Regulation* provides that the RRT must:

> (a) describe how the tariff may change during the period it is intended to have effect,
> (b) include the terms and conditions under which the owner proposes to offer electricity services, and
> (c) state how the following information will each be shown separately in the tariff and on customer's bills:
> (i) the electric energy charge;
> (ii) the administrative charge, which may include a billing charge, as a dollar amount for each period specified in the tariff;
> (iii) the delivery charge for distribution access service and system access service separately as either
> (A) a distribution charge and transmission charge, or
> (B) a fixed delivery charge and variable delivery charge;
> (iv) rate riders, if applicable;
> (v) if applicable, shown under the heading "local access fee" any amount levied under section 45 of the *Municipal Government Act*, or Schedule 1, section 21 of the *Metis Settlements Act* or by bylaw under the *Indian Act* (Canada).

Section 4 of the *RDS Regulation* outlines conditions for a transition rate tariff.

Section 5(1) outlines what the Board must consider when reviewing an application for approval of an RRT. That section states:

> 5(1) When considering an application for approval of a regulated rate tariff under section 103 of the Act, the Board must
> (a) have regard for the principle that a regulated rate tariff must provide the owner with a reasonable opportunity to recover the prudent costs and expenses incurred by the owner and a reasonable return, and
> (b) examine the reasonableness of the owner's billing costs and other costs the Board considers appropriate in the prevailing circumstances, without regard to any overall increase in costs due to the separation of distribution access service and the provision of electricity services.

## 2.2 Application of Relevant Legislation

### Views of the Interveners

### Ab-Com

The Aboriginal Communities and St. Michael's Extended Care Society (Ab-Com) supported the Reply Argument provided by the Consumer Group.

### ATCO

ATCO submitted that of fundamental importance in this proceeding was the "new world" model introduced by the recently enacted gas and electric legislation which reflected the Government's stated policy objective of ensuring continued development of a fair and competitive electricity and natural gas marketplace for consumers. ATCO stressed that when examining the Application, it was imperative that the Board has regard to the explicit provisions of the legislation.

ATCO submitted that interveners have chosen to ignore the new legislative framework by providing evidence that allegedly establishes the "financial impact" on ratepayers of the proposed sale and tariff applications and that compares the pre-separation non-energy revenue requirements versus post-separation non-energy revenue requirements. ATCO claimed that such evidence presumably asked the Board to utilize historical "old world" costs as a benchmark for determining the appropriate level of costs going forward. ATCO argued that such a cost comparison was not permitted under the new legislative scheme because the "new world" dictated that the reasonableness of the applied for costs be judged on their own merit.

ATCO submitted that Calgary acknowledges that the new legislative framework requires the separation of the distribution and gas service functions, but fails to comprehend what this entailed.

ATCO submitted that it is plainly evident in section 5 of both the *RDS Regulation* and the *DGS Regulation* that there were certain costs that the Board must and must not consider when examining an application for approval of a RRT/DRT.

ATCO claimed that section 5(a) of the *DGS Regulation* and section 5(1)(a) of the *RDS Regulation* clearly stated that the Board must have regard for the principle that a RRT/DRT must provide the RRP and DSP, respectively with a reasonable opportunity to recover prudent costs and expenses. ATCO noted that it agreed with DERS that the Board was explicitly directed to permit recovery of prudently incurred costs and expenses related to the provision of "gas services" and "electricity services."

ATCO argued that section 5(b) of the *DGS Regulation* and section 5(1)(b) of the *RDS Regulation* (the Separation Cost Provisions) provided explicit direction in regard to what the Board must not consider when examining the reasonableness of applied for costs. ATCO noted that similar provisions applied in respect of the Board's consideration of distribution tariff applications in section 10 of the *Natural Gas Billing Regulation and* section 5 of the *DT Regulation.*

ATCO submitted that section 5 of the *DGS Regulation* and the *RDS Regulation* specifically contemplated that:

(a) the retail function will be separated from the distribution function;

(b) the costs related to providing the separated retail function will be unbundled from the distribution function; and

(c) the Board shall not have regard to overall increases in costs due to the separation and unbundling or the regulated retail functions and the distribution services function.

ATCO argued that, under the new legislative scheme, the Board continues to be charged with making a determination concerning whether applied for costs were just and reasonable and if specific costs of providing service were determined to be inappropriate, the Board had full, explicit authority and jurisdiction to disallow such costs. ATCO submitted that such a determination must, however, be made in the context of the new legislative framework.

ATCO claimed that when considering whether an applied for cost – whether it be a "billing or other cost" – was just and reasonable, the Board was not permitted to have regard to overall increases in costs due to separation and unbundling. ATCO submitted that the Board must examine whether or not the Applicant had justified the costs included in their own right, and not examine the reasonableness of such costs by a comparison of what such costs were under the old legislative framework (pre-separation) and what they would be under the new legislative framework (post-separation).

ATCO argued that the new world mandated complete and utter separation of the regulated distribution function from the retail function, with the party appointed to perform the retail function being required to bring forth its own stand-alone tariff for approval.[5] ATCO argued that the plain language of the legislation clearly imposed separate roles and responsibilities. ATCO submitted that it was both necessary and desirable for the costs related to providing the regulated retail function to be completely unbundled from the regulated distribution function in terms of furthering the objectives of the Government of Alberta and development of the competitive market.

ATCO claimed that the provision of a stand-alone service required the inclusion in the revenue requirement of all prudent and reasonable costs required to provide such service, that the new market structure necessitated that a fully burdened cost standard be employed, and that failure to do so would be inconsistent with the legislation.

ATCO submitted that the only thing the Board was precluded from doing was making a comparison that the Government of Alberta clearly felt was not appropriate in the circumstances. ATCO submitted that it was its understanding of the legislation that the government has already weighed that aspect of the public interest and has concluded that prudently incurred costs that resulted in increases in costs due to the separation of the retail and the distribution function were justified by future benefits that customers would receive. Therefore, any comparison to historical costs (pre-separation) as a basis for determining the just and reasonableness of future costs (post-separation) was explicitly precluded under the new legislation.

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[5] As noted in the Transfer Proceeding argument, ATCO has further considered the issue of mandatory separation and agrees with the positions advanced by DERS regarding a proper legal interpretation of the applicable legislation (which are consistent with the business views expressed by ATCO in the Transfer Proceeding that the status quo will not continue).

ATCO claimed that a reasonable assessment of the future, absent approval of the transfer of the regulated retail energy functions from ATCO to DERS, would be a separation of these functions from the day to day ownership, operation, management, and maintenance of pipes and wires.

ATCO submitted that, if the Retail Sale Application was not approved, it must segregate these functions in accordance with the legislation and Government policy (which, among other things, recognizes that the market could serve customers best if ownership was separated) and in doing so, ATCO argued that it would incur costs very similar to those put forth by DERS in its Tariff Application. ATCO claimed that the basic premise of Calgary's assertions, that ATCO could somehow avoid similar costs of separation, was flawed.

ATCO argued that Calgary's assertion, that any separation costs that would not have been incurred by ATCO to separate the functions cannot be considered prudent, was clearly a misguided attempt to "cap" the amount of costs that could properly be considered prudent separation costs.

ATCO submitted that Calgary was not correct in its assertion that the major costs associated with the separation of functions by ATCO were included in the ATCO Gas 2003/2004 GRA, because the costs included in the GRA were presented on the assumption that the transfer of retail functions would not proceed and those costs simply did not reflect the overall costs that would necessarily have to be incurred to achieve the complete separation of functions required under the new legislative scheme.

ATCO submitted that Calgary's suggestion, that costs of separation could have been avoided had a different service provider been appointed, was of no assistance given that such an approach would have implicitly limited the choice to one of the two incumbent participants in the Alberta market. ATCO argued that the appointment of such a service provider would not have met the objective of introducing a new player into the Alberta marketplace and thereby enhancing competition, with the associated benefits.

AUMA/CE asserted that there was no requirement to implement the separation of the retail function given that separation was not mandated by the legislation, nor was there any requirements for a "fully allocated" or "fully burdened" or a "stand-alone" cost standard in section 5 of the referenced legislation. ATCO argued that these provisions must be read in light of the overall legislative framework and stated policy objectives of the Government of Alberta. ATCO submitted that the cost standard adopted must be consistent with the objective of fostering a more competitive retail energy marketplace. ATCO submitted that a level playing field requires that all participants must compete on a stand-alone, fully burdened cost basis.

### AUMA/CE

AUMA/CE[6] noted that DERS referenced Alberta government policy and intent and how its Application furthered that intent. However, no government official was called to speak to policy and intent, nor whether the transactions as structured met with government policy and intent.

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[6] Argument was submitted on behalf of the Alberta Urban Municipalities Association (AUMA) and the City of Edmonton (CE). The interests of the CE are limited to the DRT and the interests of the AUMA concern both the DRT and RRT.

AUMA/CE submitted that sections 5 of the *DGS Regulation* and *RDS Regulation* did not mandate separation of the retail businesses from other functions and that these sections did not specify any requirements for a "fully allocated" or "fully burdened" or a " stand-alone" cost standard. AUMA/CE argued that these sections were intended to assist the Board in determining the reasonable and prudent costs that the applicant needed to perform the regulated services.

AUMA/CE claimed that if an increase in billing costs arose due to the separation of the retail business and due to unregulated services also being provided, the Board must consider the overall reasons for and reasonableness of the increase.

AUMA/CE argued that if the increase in other costs was due to employing staff with greater than needed qualifications and experience because that type of staff was also required to service an unregulated market, or because the allocation of costs to the regulated function was too high, the Board was not and should not be constrained in looking at the overall reasons for and reasonableness of the increase.

AUMA/CE claimed that DEML's costs did not follow the "stand-alone" concept because of the significant overlap of costs between the regulated and non-regulated functions. AUMA/CE argued that DEML employed arbitrary allocation methodologies (biased or otherwise) to separate regulated from non-regulated functions. AUMA/CE submitted that the way DEML was choosing to conduct its regulated business was clearly not on a "stand-alone" basis, and therefore ought not be treated as such.

AUMA/CE submitted that DEML was wrong in its conclusion that the Board was not permitted to compare post separation costs with pre-separation costs because the Board was directed not to take into account any increase that arises from such separation. AUMA/CE argued that the Board had no choice but to look at the pre-separation costs to determine if in fact there had even been an overall increase in costs post separation. AUMA/CE submitted that the Board had to look at the pre-separation costs to help it determine if the increase was solely due to the separation of the retail business from the distribution business, or if there were other reasons for the increase, such as hiring over qualified personnel that provide unregulated services, or using too many management or executive personnel to perform regulated functions. AUMA/CE argued that looking at the pre-separation costs and the specific functions performed would assist the Board in determining if the costs claimed were reasonable and prudent, and solely due to the separation of the regulated retail business.

AUMA/CE disagreed with ATCO's suggestion that a comparison of the "historical (pre-separation)" costs to "future (post-separation)" costs was of "little value." AUMA/CE submitted that the Board and Interveners often compared "actual" costs of prior periods to proposed costs in a GRA or GTA and that this comparison was one of many tools that the Board used in determining the reasonableness of the proposed costs (including testing forecasts).

AUMA/CE claimed that ATCO's suggestion, that similar costs would be incurred by ATCO if it had the retail function, was simply speculation because no evidence was produced to substantiate the claim.

AUMA/CE submitted that DERS rationale for requiring a "fully burdened" cost standard was flawed. AUMA/CE argued that since the DEML overall business plan was to "switch" customers to unregulated retail services as quickly as possible, it contradicted DERS's statement that the "incremental" cost standard could no longer be justified because DERS was no longer providing a temporary service.

AUMA/CE argued that any costs of DERS that required approval of the Board should be based on the evidence in the proceeding, and should be based on a prudent cost standard as determined by the Board because the Board was not bound to accept the "fully allocated" or "stand-alone" cost standard.

### Calgary

In order to determine the appropriateness of many of the separation related cost items advanced by DERS in the proceeding, Calgary[7] submitted that the Board must first reach a determination of the proper interpretation of section 5 of the *DGS Regulation*.

Calgary submitted that the Board must determine what costs arose from the legislation and what costs arose out of the retail sale. Calgary also noted that additional costs arising from measures to comply with the *Code of Conduct Regulation*, given that both regulated and unregulated activities were contemplated by DERS's affiliates, were not costs arising from the separation of the retail and distribution functions. Calgary argued that costs arising from legislation are prudently incurred costs of separation.

Calgary submitted that to the extent that a residual balance remained between the current costs and the combined costs of ATCO's distribution service and DERS's regulated retail service, that balance should only constitute the costs that were necessarily and prudently incurred to accomplish the functional separation of the distribution function and gas services as required by the new legislation.

To give meaning to section 5(b) of the *DGS Regulation*, Calgary submitted that a distinction must be drawn between legislated costs relating to functional separation and incremental business driven costs that emanated from the Retail Sale transaction.

Calgary submitted that the Retail Sale Application dealt with two different matters. The first matter dealt with the separation of the distribution and regulated retail (default supply) functions. The second matter involved a discreet business decision by ATCO to sell certain functions to a third party. Calgary submitted that the arrangements resulting from ATCO's business decision should not increase costs beyond the costs that ATCO would have incurred if ATCO separated the distribution and default supply functions and continued to perform both functions internally. Calgary claimed that if ATCO sold its distribution service to another company, the Board would not allow the purchaser to increase rates to a level that was 20% higher than ATCO's costs. Calgary submitted that just because the two matters were occurring at the same time was no justification for allowing all incremental costs by suggesting that they were caused by or contemplated by the new legislation.

Calgary submitted that the legislation spoke clearly of the requirement of the separation of the distribution function from the default supply function and nothing more. Calgary argued that ATCO, in separating these functions, could have done any number of things including approximating the status quo.

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[7] The City of Calgary (Calgary) noted in its argument that it did not have any specific comments regarding the RRT but that most of its comments under the DRT also apply to the RRT.

Calgary acknowledged that functional separation may increase overall billing costs in the short run since ATCO incurred additional costs to establish the RRO on the electric side. Calgary also acknowledged that, if ATCO Gas was to functionally separate its default supply from its distribution service, there may be some additional cost but Calgary submitted that many of these costs had already been reflected in the forecasts for the 2003/2004 GRA of ATCO. Calgary submitted there might be additional costs, but the magnitude would be much less than what Calgary estimated for the outcome of the Application.

Calgary argued that the regulations related to the setting of tariffs on a prospective basis and that there was no mention of recovery of costs incurred prior to the provision of gas services by a default rate provider (i.e. integration, start-up and delay costs).

Calgary submitted that if the regulations were properly applied to the Application, the financial harm to customers would be much lower than the $47.4 million calculated by Calgary. Calgary suggested customers would only bear those costs that would have been incurred had ATCO separated the distribution and default supply functions and continued to perform both functions internally.

In regard to the reference to "billing costs" in section 5(b) of the *DGS Regulation*, Calgary noted that "billing" was defined in the *Natural Gas Billing Regulation* as follows:

> 1(b)"bill" or "billing" means an account for charges arising from the provision of gas services and gas distribution services to a customer, including applicable taxes, franchise fees, and other charges;

Calgary submitted that billing costs meant only the charges for distribution and gas services would appear on the bill.

Calgary noted that Gas Services[8] and Retail Gas Services were uniquely defined in the GUA[9] and that Retail Gas Services were defined as Gas Services that were provided by a retailer directly to customers and not provided under a DRT. Therefore, in the context of this proceeding, Calgary submitted that DERS would provide Gas Services under a DRT and Direct Energy Preferred (DEP) would provide unregulated Retail Gas Services directly to customers. Calgary submitted that Gas Services means the DRT and therefore, under section 5(b), the Board could not consider any overall increase in billing costs if the overall increase was "due to the separation" of distribution rates and the DRT. Calgary argued that in order to determine any overall increase in billing costs, all billing costs pre-separation must be compared to all billing costs post-separation.

Calgary submitted that a common sense interpretation of the regulation would suggest that the legislature contemplated that the Board would total all billing costs and compare these against the pre-separation costs. Calgary argued that all billing costs included the costs of both ATCO and DERS and that these costs would be the "other costs appropriate in the circumstances". Calgary claimed that to the extent there was an increase in "overall billing costs" (new world versus old world), the Board must allow the increase, but only if the increase was due to the separation of the distribution and DSP functions.

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[8] Gas Services are defined in Section 28 of the GUA as the gas that is provided and delivered and the services associated with the provision and delivery of the gas, including arranging for the exchange or purchase of the gas, making financial arrangements to manage the financial risk associated with the price of gas, arranging for gas distribution service, arranging for delivery of gas to the gas distributor's specified receipt point or points, storage, billing, collection and responding to customer billing inquiries, maintaining information systems, and any other services specified by the Minister by order as gas services.

[9] Section 28

Calgary submitted that in order to determine what costs were "due to the separation" of these functions, one must determine whether the new legislation caused the costs, or if they were incremental to those costs caused by the legislation and as such, unrelated sale costs.

Calgary argued that many costs of the sale transaction were not caused by the legislated separation of the distribution function and the default supply function, and if ATCO chose to remain the DSP none of these costs would arise. Calgary submitted that the majority of separation costs sought to be recovered by DERS were incremental to what ATCO would have incurred to functionally separate. Calgary stated that DERS's costs of separation were particular to its circumstances and existing assets and business resources in Alberta. Calgary submitted that if ATCO had authorized another Alberta utility with existing billing and customer care facilities to provide the default supply function, integration and delay costs would not have arisen and there may have been synergistic opportunities (i.e. economies of scale). Calgary suggested this would have allowed for cost reductions.

Calgary submitted that ATCO improperly suggested in its Retail Sale Application rebuttal evidence that the $47.4 million of incremental costs associated with this transaction would hae occurred even if ATCO retained responsibility for the DRT, because in Calgary's view, ATCO had admitted under cross examination that there was nothing in the current legislation and regulations that required ATCO to incur those costs. Calgary submitted that ATCO stated that the current legislation did not preclude it from separating its functions in the same manner as proposed in this transaction. However, Calgary argued that a separation which required ATCO to hire 27 additional Full Time Equivalent's (FTE), and to set up security and confidentiality barriers, could hardly be described as incurring prudent costs. Calgary submitted that those costs would not be necessarily incurred under the current legislation and could therefore not be justified as prudent.

Calgary submitted that none of the costs listed at pages 9 through 11 of ATCO' rebuttal evidence in the Retail Sale Application needed be incurred to comply with the legislation, and these costs would only arise if the legislation changed to mandate separate ownership of the retail market from ownership of the wires and pipelines. However, Calgary argued that the definition of "retail gas services" in the legislation did not include the regulated default supply function.

Calgary submitted that the Alberta Government contemplated a separation of the distribution and the default gas supply function and separation between regulated service (distribution and default gas supply) and unregulated retail service. Calgary submitted that if a company provides both regulated and unregulated service, then the *Code of Conduct Regulation* required a clear separation. Calgary argued that the separation of regulated and unregulated services had cost consequences and these costs could not be recovered in regulated rates.

Calgary claimed that section 5(b) said nothing about the recovery of costs for compliance with the *Code of Conduct Regulation*. Calgary argued that a DSP did not have to provide services concurrently in the unregulated retail market.

Calgary submitted that the *Code of Conduct Regulation* permitted the transfer of customer information between the DSP and the distributor without customer consent. Calgary also argued that the Code of Conduct did not prevent a distributor and its default rate provider from sharing a common billing system, including a common database. Calgary submitted that security barriers set-up between ATCO and DEML, as described in ATCO's Retail Sale Application rebuttal evidence, were not necessary under the current legislation and Calgary argued that this type of separation appeared to be one of the drivers behind Calgary's estimated $47.4 million cost increase associated with this transaction.

Calgary claimed that section 5(b) of the *DGS Regulation* was not inconsistent with established regulatory principles that the applicant had to prove that it had chosen the most cost-effective method of separation and had minimized transaction costs for ratepayers. Calgary submitted that the appropriate test was not a comparison of the costs of the status quo (the costs of not separating the default supply function) but rather a comparison of the costs related to separation of the default supply and customer care function that resulted from this transaction, relative to other alternatives that could result in lower transaction and ongoing costs for ratepayers.

Calgary argued that ATCO's suggestion that it would separate its distribution function from default supply function and incur $47.4 million in increased costs annually, simply because it anticipates some fashion of amended legislation, or because it said there was nothing stopping it from doing so, could not be supported. Calgary claimed that this evidence was introduced solely to deflect attention from attempts to divide costs between those caused by the new legislation and those that flowed from ATCO's business decision to enter into this particular sales transaction.

Calgary submitted that ATCO and DEML placed a heavy reliance on the government's press release, which was cited as evidence of government policy.[10] Calgary submitted that one statement in one press release could not be used in isolation as a tool to gain insight into the mind of the legislators. Calgary submitted that the legislation and regulations should be considered without external aids. Calgary also noted a comment by the Board in Decision 2003-040:

> With respect to the views of the government on de-regulation and competition, the Board is guided primarily by actual legislation. The Board will not give any weight to the parties' interpretations of government policy developed through private meetings or extrapolation of government policy.[11]

Calgary noted that the press release stated that the new legislation may increase costs "in the short term" and Calgary argued that the Alberta government could not have envisaged increased costs amounting to $47.4 million annually.

Calgary submitted that DERS had somehow tried to link the nature or extent of separation with the inclusion of fully burdened costs in the RRP.

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[10] Application No. 1302109, Exhibit 002-01, Direct Energy Regulated Services – Regulated Rate Tariff and Default Rate Tariff Applications, Volume 2, Appendix A.

[11] Decision 2003-040 – ATCO Group, Inter-Affiliate Code of Conduct, dated May 22, 2003, p. 18

Calgary argued that functional separation was completely independent of cost allocation and Calgary's comments with respect to separation were in no way linked to cost allocation between the distribution function and the provision of either regulated gas or electricity services. Calgary submitted that the first step was separation, and not the sale; and the second step was cost allocation. Calgary claimed that once separation had taken place, the most appropriate cost allocation method could then be selected. Calgary submitted that the allegation by DERS that Calgary was advocating an incremental cost standard for the RRP was without merit and should be disregarded by the Board.

### Consumer Group

The Consumer Group[12] submitted it would be more appropriate for the Board to consider the Application to have been made by DEML because it was not appropriate for a business unit to make an application. The Consumer Group submitted that the Board should consider the Application to be made by the corporate entity or "person"[13] since a mere business unit had no recognizable legal status.

The Consumer Group argued that this lack of a recognizable legal status also allowed DEML to circumvent the proposed federal *Privacy Act* provisions since both DEP and DERS were part of the umbrella of DEML, the one legal corporate entity. The Consumer Group submitted that DEML would be subject to the proposed provisions on release of customer information, but only in relation to the release of information to third parties, since it was doubtful the two non-legal divisions of DEML would have to meet the same requirements when transferring customer information between themselves. The Consumer Group claimed that DERS's customers should have the same rights and protections as customers of utilities with distinct corporate status and to have the Code of Conduct as the only "safeguard" for DEML customers was unacceptable.

The Consumer Group noted that in the event the Retail Sale Application was approved, and to the extent the Board considered it appropriate to impose conditions on the approval, the Consumer Group would advocate and support the imposition of a number of conditions it identified in its Retail Sale Application argument.

The Consumer Group submitted that notwithstanding section 5 of each of the *RDS Regulation* and the *DGS Regulation*, billing and other costs must first be determined by the Board to be reasonable before they could be approved.

The Consumer Group submitted that the Board, acting pursuant to its broad supervisory and regulatory powers, was free to make any order or condition it found to be in the public interest, subject only to such order being expressly contradicted by the wording of a legislative provision. The Consumer Group submitted that the Supreme Court of Canada and Alberta Court of Appeal have recognized that the Board's legislative framework gave it a very broad mandate to protect consumers and the public interest and that protection was clearly one of the critical objects of the legislative framework.[14]

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[12] The Consumer Group –The following parties collectively referenced as the Consumer Group (CG) filed joint Argument for the Application and noted that most, if not all, of the parties would be filing separate submissions in relation to the non-energy revenue requirement allocation, primarily a phase II type matter. Aboriginal Communities / St. Michael's Extended Care Society (Ab-Com), Alberta Irrigation Projects Association (AIPA), Alberta Rural Utilities Association (ARUA), Canadian Forest Products Ltd. (Canfor), Consumers' Coalition of Alberta (CCA), Public Institutional Consumers of Alberta (PICA). The CG noted that unless expressly limited to either electricity or gas, its submissions should be considered as having been made in regard to both the DRT and RRT.

[13] *Interpretation Act*, RSA 2000, c.I-8 s.28 (1)(nn); and *Business Corporations Act*, RSA 2000, c.B-9 s.1(x) and 16(1)

The Consumer Group submitted that there were no prohibitions in section 5 of either of the *RDS Regulation* or the *DGS Regulation* as to what, or how, the Board could use the evidence before it to determine if the proposed costs were prudent. As there was no such prohibition, and consistent with rules of statutory interpretation, a comparison of pre and post separation costs was permissible and the Consumer Group submitted that such a comparison was reasonable and prudent.

The Consumer Group also argued that if the cost for a particular function was the same for ATCO, DERS and a third party service provider, all things being equal, the cost was most probably prudent and reasonable and resulted in no harm to consumers.

The Consumer Group submitted that the assertion that the Board was precluded from doing a comparison of pre and post separation (or third party service provider) costs, was merely an expression of opinion and nothing more than a speculative interpretation of Government policy.

### HVAC

HVAC[15] claimed that section 5 of each of the *RDS Regulation* and the *DGS Regulation* imposed a restriction upon the traditional inquiry otherwise applicable to these circumstances, but this restriction only relates to separation costs that had not been defined. HVAC argued that this fact should not mean that it was proper for it to be considered an all-encompassing category or a blank cheque. HVAC submitted that DERS had the onus of proof to demonstrate that its costs belonged in the "separation" category.

HVAC noted that the Applicant in this proceeding was DERS, a business unit of DEML. HVAC submitted that DERS had agreed that the present applied for approval in the Application was conditional upon the Board approving and authorizing DERS to be a DSP pursuant to section 2 of the *DGS Regulation*. HVAC argued that the section 2 *DGS Regulation* precondition could not be met given the fact the business unit, DERS, was an unincorporated entity and not a "person". HVAC also submitted that the same defect applied in the circumstances of the Application, since the approval under subsection 3(2) of the *DGS Regulation* may only be granted to a DSP who in turn must be a "person" at law. In the context of any section 3 *DGS Regulation* approval, HVAC argued that DERS should be required to become a legally recognized person, and one in particular which was distinct from any DEML unregulated retailer. In addition, and as part of the required separation, HVAC submitted that DERS should be required to arrange its affairs such that separate management, control and direction existed over the regulated functions of DEML to address actual or perceived conflicts of interest.

HVAC submitted that the retail gas deregulation in Alberta was premised upon the separation and segregation of the regulated and unregulated functions and as such, DEML, itself, could not become the DSP since it was already an unregulated licensed natural gas direct marketer.

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[14] Dome Petroleum Ltd. v. Alberta (Public Utilities Board) (1976) 2 A.R. 453, affd. [1977] 2 S.C.R. 822.

[15] HVAC – Lennox Inc., Heating Refrigeration and Air Conditioning Institute of Canada, The Mechanical Contractors Association of Alberta, and Sheet Metal Contractors Association of Alberta. HVAC provided argument on the DRT.

HVAC argued that having the same person or company carry out both of the regulated and unregulated activities would also be completely inconsistent with Mr. Massara's testimony, wherein he stated the intention of establishing separate companies to carry out the regulated and unregulated functions would avoid confusion.

HVAC disagreed with DERS's position that suggested the use of business units was an acceptable "regulatory norm" based upon Board Decision No. 2001-97.[16] HVAC submitted that the issue concerning business units in Decision 2001-97 related to whether ATCO Gas and Pipelines Ltd., could continue carrying out its regulated gas utility responsibilities by arranging its affairs into business units. HVAC argued that this arrangement did not in any way alter the fact that ATCO Gas and Pipelines Ltd. remained the owner of the gas utility under the GUA, and subject to Board jurisdiction and authority. HVAC claimed that Decision 2001-97 did not, for example, grant approval to any of the business units to become an owner of a gas utility as that term is defined in the GUA. HVAC also argued that ATCO Gas and Pipelines Ltd. remained the regulated entity upon which the Board could enforce orders, and impose penalties, if necessary, pursuant to section 56 of the GUA.

### Views of DERS

DERS submitted that the Board's jurisdiction to consider and determine a RRT and DRT application arose from the new legislative regime recently enacted in Alberta, which was intended to enhance and strengthen competition in the retail energy markets through the mandated separation of the regulated retail function from the distribution function. DERS argued that the complete separation of these functions was sound Government policy and was vital if there was to be a level playing field upon which competition and customer choice among regulated and unregulated retail services could occur.

DERS noted in the Backgrounder to Alberta Energy's August 21, 2002 News Release, (the Backgrounder) that the Government stated the following concerning natural gas and electricity customer choice:

- Better aligning natural gas and electricity customer choice will strengthen the competitive retail gas and electricity markets and provide consumers with a greater choice of energy suppliers and a variety of new product offerings.
- By enhancing customer choice, consumers should see better customer service, lower costs and greater choice of energy suppliers.
- The market can serve customers best if ownership of the retail market is separate from ownership of the wires and pipelines. The government will not mandate the separation but will remove systemic barriers, which inhibit separate ownership…[17]

DERS noted that the Government did not intend to mandate the separation of ownership of the wires and pipelines from ownership of the regulated retail function, but DERS submitted that the specific provisions of the new legislation and the Government's policy statements indicated that complete operational separation of these two distinct functions was necessary in order to achieve the level playing field objectives of the Government's policy and to strengthen the Alberta retail energy market.

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[16] Decision 2001-97– ATCO Pipelines South, 2001/2002 General Rate Application, Phase I, dated December 12, 2001

[17] Application No. 1302109, Exhibit 002-01, Direct Energy Regulated Services – Regulated Rate Tariff and Default Rate Tariff Applications, Volume 2, Appendix A.

DERS submitted that the regulated retail service provider must therefore operate on a stand-alone basis, that reflected the fully burdened costs of providing this service, in order for competitive retailers to be able to compete against regulated offerings on a level playing field basis.

DERS submitted that a more competitive marketplace could not be achieved unless regulated and unregulated service providers competed on a level playing field. If the regulated retail service provider had cost advantages as a result of the partial unbundling of the retail function, or due to cross-subsidization by the distribution business, there would not be a level playing field and the development of a competitive retail market would be thwarted.

DERS submitted that it was clear from the Backgrounder and the explicit language of section 5 of both the *RDS Regulation* and the *DGS Regulation* that the Government of Alberta contemplated that there would be an increase in billing costs arising from the separation of the regulated retail function and the distribution function.

DERS argued that an incremental cost structure for a regulated retail service provider, relative to a fully burdened billing cost structure for other retail service providers, conferred upon the regulated service provider a cost advantage and, thus, a competitive advantage. DERS submitted that if any cost savings, associated with an incremental cost structure, accrued to the benefit of the RRP, then competitive retailers, burdened with the full cost of billing, would find themselves at a competitive disadvantage and such a result would weaken, if not stifle, competition.

DERS submitted that in the short-term, it was anticipated that the vast majority of customers would continue with regulated retail service, and if the government's level playing field objectives were fostered over the longer term, competitive forces were expected to become more prominent with the result being greater migration of customers to unregulated retail services. DERS also submitted that in order to achieve that outcome, it was essential that the retail function be completely separated from the distribution function.

DERS noted that DEML's decision to enter the Alberta retail energy market was predicated on the new legislation creating a market structure and regulatory regime that reflects the regulated service provider bearing its fully burdened costs, without cross-subsidy from the distribution function, and that any regulatory or legislative measure that moves away from a fully separated regulated retail function would be inconsistent with the basis for DEML's decision to enter the Alberta market.

DERS submitted that section 5 of each of the *RDS Regulation* and the *DGS Regulation* provide the Board with clear direction on the cost recovery principles to which it must have regard and the matters that it is not permitted to take into account when considering an RRT & DRT application.

DERS submitted that from section 5(1)(a) of the *RDS Regulation* and section 5(a) of the *DGS Regulation*, it was abundantly clear that, when approving an RRT or DRT, the Board must afford the owner or the person acting on behalf of the owner, with a reasonable opportunity to recover prudent costs and expenses incurred with respect to the provision of RRT service.

DERS also submitted that it was clear from section 5(1)(b) of the *RDS Regulation* and section 5(b) of the *DGS Regulation* that the Government has, when faced with the separation of the distribution function and the regulated retail function, directed the Board to not take into account any increase that arises from such separation. DERS argued that it follows that the Board was not permitted to compare post separation costs with pre-separation costs. DERS submitted that these sections do not prohibit the Board from considering whether the costs included in an applied-for revenue requirement are prudent. Accordingly, if separated costs, when considered on their own merits, are determined to be prudent, the fact that such prudent costs might result in an increase over what the costs were prior to separation must not be taken into account by the Board when deciding to approve revenue requirement items.

DERS noted that Calgary acknowledges that the new legislation mandates the separation and unbundling of regulated retail services from the distribution function, but DERS submitted that Calgary's concept of "separation" is nothing more than applying the incremental cost standard applied in respect of ATCO Electric's Regulated Rate Option Tariff. DERS submitted that Calgary refers to a "functional separation" and to the evidence of Mr. Stephens at the hearing that "there may be some additional staff, personal computers and desks required, but the costs would be slight…". DERS argued that based on this faulty premise and its interpretation of the legislation, Calgary seems to advance the proposition that most of the cost increases calculated by Calgary arise due to the transaction, and not the legislation.

DERS submitted that it was clear that the Alberta Government did not intend to continue the RRO model, otherwise, it would not have been necessary to repeal the *Regulated Rate Option Regulation* (*RRO Regulation*) and replace it with the *RDS Regulation*. DERS also submitted that it would not have been necessary to include specific directions to the Board in section 5 of each of the *RDS Regulation* and the *DGS Regulation*.

DERS submitted that under the *RRO Regulation*, complete separation was not required because the Board held that since the RRO was temporary, only the costs that would disappear at the end of the transition period should be included in the RRO.[18] DERS submitted that this avoided the costs being taken out of the distribution tariff and later having them re-absorbed back into the distribution tariff after the end of the RRO.

DERS submitted that since the use of the incremental cost standard and partial unbundling were achieved under the *RRO Regulation*, there would have been no need for the Government to include section 5 in the new regulations if it had intended incremental costing and partial unbundling to carry forward. Therefore, DERS submitted that the alteration [to the RRO model] must be taken to have been made deliberately and the new regulations must be intended to achieve a framework different than that which existed under the prior *RRO Regulation*. DERS submitted that section 5(b) indicates that the government intended to move away from partial unbundling and thereby achieve complete separation of the regulated retail function.

DERS submitted that Calgary's assertion that some of the costs incurred by DERS arise because of the transaction and not by the legislation is neither supported by the legislation itself, nor the facts on the record. DERS submitted that it is absolutely clear that any increase in overall costs arise out of the requirement for a complete separation.

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[18] Decision 2000-88, p. 25

DERS submitted that it is clear that Calgary and the other opposing interveners[19] do not like the outcome of the new legislative framework and are presenting transparent arguments to avoid the intended outcome of that framework.

DERS submitted that it is clear from the Backgrounder and the legislation that the complete and utter separation of the regulated retail function from the distribution function is required and ATCO would have to establish a stand-alone, fully cost burdened regulated retail service provider if it were not to sell its retail business to DEML and it would be even better if integrated distribution companies were to sell their regulated retail business so that there would be a separation of ownership.

DERS submitted that the Government considered the separation of ownership to be better than the separation of the functions because under separate ownership, there can be absolute assurance that the new regulated retail service provider operates on a stand-alone, fully burdened cost basis without any potential cross subsidy from the distribution business. DERS submitted if an incumbent distributor establishes a separate regulated retailer, it is possible that certain costs associated with the regulated retail business could be supported by the distribution business and such a result would be inconsistent with the objective of retail competition among regulated service providers and retailers occurring on a level playing field basis.

DERS submitted that in arriving at its decision respecting a RRT and DRT, the Board is required to afford the regulated service provider a reasonable opportunity to recover its prudent costs and expenses and *a reasonable return* and if those prudent costs and expenses and reasonable return result in an increase that is attributable to the separation of the regulated retail function from the distribution function, then that increase (no matter over what time period and at what level) cannot be taken into account as a means of disallowing costs that are otherwise judged to be prudent.

DERS submitted that Calgary did not take into account all the facts when it made its assertion that "[any] separation costs that would not have been necessarily and prudently incurred by ATCO to separate functions cannot be considered prudent. DERS claimed that Calgary did not take into account that, in its Rebuttal Evidence for the Retail Sale Application, ATCO indicated that if the sale to DEML were not to proceed, ATCO would incur costs that are similar to the types incurred by DERS and at the same or substantially similar level in order to achieve a complete separation.

DERS noted that HVAC complained about the fact that DERS was a business unit of DEML and therefore, in and of itself, was not a "person." DEML submitted that the HVAC's arguments on this point are inconsequential. DERS noted that ATCO has applied for approval of arrangements with DEML and both the Electricity Assets Transfer Agreement (EATA) and the Gas Assets Transfer Agreement (GATA), filed in the Retail Sale Application, contemplate that the regulated retail service function will be retained within DEML and that the unregulated function will be assigned to an affiliate, that being Direct Energy Partnership. DERS noted that it was part of DEML, and submitted that DEML has never purported that DERS was some kind of separate legal entity. DERS argued that the Board has previously accepted this type of structure in Decision 2001-97, concerning ATCO Pipelines South, 2001/2002 GRA, Phases I and II, where the Board addressed the regulatory status of ATCO Pipelines.

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[19] Aboriginal Communities, AUMA/CE, Consumer Group, HVAC and AFREA

DERS noted the position of Calgary and the Board's views on page 4 of that Decision:

> **Calgary**
> Calgary submitted that, for the test periods, 2001 and 2002, AGPL is the legal entity, the legally regulated utility, and that ATCO Gas South (AGS), ATCO Gas North (AGN), APS and ATCO Pipelines North (APN) are trade names or, at best, best [sic] business units.
>
> **Views of the Board**
> The Board notes the comments of ATCO and Calgary regarding the regulatory status of APS. The Board considers that it was appropriate for AGS and APS to file their GRAs separately in these proceedings.

DERS also noted the Board's comment in regard to the filing of Annual Reports by the business units of AGPL:

> However, the Board notes that the latest annual report of finances and operations, filed as required by the Board for the year 2000 was for ATCO Gas and Pipelines Ltd. The Board expects that for the year 2001 and subsequently, ATCO will file a separate annual report for each of ATCO Gas South, ATCO Pipelines South, ATCO Gas North and ATCO Pipelines North.[20]

DERS submitted that it was clear from this passage that the Board recognizes the business unit structure for utility operations and that the use of DERS by DEML is not something outside the regulatory norm for entities within the Board's jurisdiction.

Furthermore, DERS argued that it was abundantly clear that DEML, as a corporation, has the capacity to enter into contracts and would be the entity against which any claims related to DERS's regulated retail business would be advanced.

DERS claimed that the *Code of Conduct Regulations* allow for the structure proposed by DEML for both the regulated and unregulated retail businesses, and that there is not a requirement that a regulated retail service provider and its affiliated retailer be separate entities. That notwithstanding, DERS notes that DEML has chosen to establish its unregulated retail business through a partnership, for which DEML is the managing partner and for which it has established a brand name that is distinctive from that of the regulated service provider.

### Views of the Board

The primary legislative issue in this proceeding is the proper interpretation of the Separation Cost Provisions in the context of the Application. Do these provisions apply, as Calgary argues, to permit only incremental cost increases, being those increases that would have occurred if ATCO had functionally separated its regulated retail function from its distribution function internally?

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[20] Section 2.3 of Decision 2001-97

Calgary argued that the separation of the regulated retail function from the distribution function necessarily would result in certain costs, however, only those costs that would have been incurred in an internal ATCO functional separation were permitted by the Separation Cost Provisions. All other costs requested by DERS should be compared to the pre-separation costs of ATCO in providing the regulated retail functions with the resulting increases falling outside of the protections offered by the Separation Cost Provisions. AUMA/CE and the Consumer Group supported the ability of the Board to compare pre-separation and post-separation costs. HVAC submitted that DERS had the onus of proof to demonstrate that its costs belong in the "separation" category.

Both ATCO and DERS took the position that the Separation Cost Provisions applied to all costs put forward in the applied for Revenue Requirement. It was their position that the Separation Cost Provisions were enacted to permit all reasonable costs, prudently incurred to achieve the separation on a stand-alone basis of the distribution function and the regulated retail functions, to be passed on to ratepayers. In the view of ATCO and DERS, this position was fully consistent with the Alberta Government's approach in the legislation and in the Backgrounder, of achieving a level playing field between regulated retail service providers and unregulated retail providers. To permit only incremental costs that would have been incurred by ATCO had it functionally separated the functions to be passed on to ratepayers would slant the playing field in the direction of the RRPs.

In Decision 2003-098 dealing with the Retail Sale Application, the Board had to determine if the Separation Cost Provisions should modify the Board's consideration of the no harm test. The Board was required to consider if the direction contained within the Separation Cost Provisions to the Board, to consider "billing costs, and other costs the Board considers appropriate in the prevailing circumstances, without regard to any overall increases in costs due to the separation" of distribution function and the regulated retail function, included only the costs that ATCO would have incurred to functionally separate the regulated retail function from the distribution function within the ATCO Group of companies, or if it also included the costs associated with the Retail Sale to DEML. At pages 10 and 11 of that Decision, the Board determined that the Separation Cost Provisions (which term included similar provisions in the *Natural Gas Billing Regulation* for Gas distribution tariff applications and in the *DT Regulation* for electricity) did apply to the costs associated with the Retail Sale and not just to the costs that would have been incurred to achieve a functional separation of functions within the ATCO Group.

> The Separation Cost Provisions provide direction to the Board in the context of an application for an electric regulated rate tariff, a gas default rate tariff or an electric or gas distribution tariff. The Board recognizes the arguments of the interveners that the Separation Cost Provisions should not apply to either the Asset Sale Transactions or to the Default Supplier Appointments and that the no harm test should fully apply without giving consideration to the Separation Cost Provisions. The Board also notes the argument that it should consider the separation of the distribution function from the Regulated Retail Functions as independent from the sale or transfer of the Regulated Retail Functions and that the Separation Cost Provisions should only apply to the former, and not to the latter.
>
> The Board considers that the intent of the legislation is aimed at giving the Board direction in its consideration of the billing costs and other costs that may arise in the course of separating the pipes and wires distribution function from the Regulated Retail Function. It may have been possible for ATCO to have first separated the distribution and

> the Regulated Retail Functions internally and then to enter into the Asset Sale Transactions and the Default Supply Appointment Agreements, but that is not what was done. The Board must deal with the Application as it is and must apply the no harm test in light of the legislation and in the circumstances before it. As previously noted, it was the intention of ATCO and Direct Energy to inextricably connect the Asset Sale Transactions and the Default Supplier Appointments. One aspect of the transaction will not occur without the other and it is the view of the Board that together, these two components form a single overall transaction. Therefore the Board considers that the two halves of the single transaction should not be separated and treated in a manner that could result in inconsistent outcomes. If the Separation Cost Provisions apply to either aspect of the transaction, they must be considered to apply to the entire transaction.
>
> The Board is of the view that the Separation Cost Provisions do apply to the Board's consideration of the Asset Sale Transactions and to the Default Supplier Appointments as they have been brought forward for consideration by ATCO in the context of an attempt to achieve the separation of the distribution and retail functions. To find otherwise, could result in the Board determining that the potential harm resulting from either the Asset Sale Transactions and/or the Default Supplier Appointments exceed the unmodified financial harm parameters ordinarily considered in the application of the no harm test with the consequent denial or conditioned approval of the applications. Such a result could potentially defeat the apparent purpose of the Separation Cost Provisions to enable or to facilitate the separation of distribution and Regulated Retail Functions by expressly recognizing that the separation may result in increased billing and other costs, and by directing the Board to disregard costs of this nature that are reasonably incurred in achieving this outcome.

The Board finds that the rationale that linked the separation of the regulated retail function from the distribution function in the context of the application of the Separation Cost Provisions to the no harm test, is equally applicable to a linkage of the reasonably incurred prudent costs incurred by DERS in establishing a stand-alone business separate and apart from the distribution function remaining with ATCO. Accordingly, the Board finds that the Separation Cost Provisions apply in the context of this Application so that when considering the billing costs and other costs that the Board finds appropriate in the circumstances, the Board will not have regard to prudently incurred, reasonable cost increases resulting from the separation of the ATCO distribution function from the regulated retail function to be carried out by DERS. It follows, therefore, that the appropriate standard to be applied in considering the prudence and reasonableness of such costs, is the stand-alone cost standard, not the incremental cost standard based on the costs that ATCO would have incurred had it functionally separated the two functions.

Again, this conclusion is supported by the findings of the Board in Decision 2003-098 wherein the Board found that the stand-alone cost standard was appropriate when considering the application of the Separation Cost Provisions to the no harm test. Reasonable costs of DERS prudently incurred, when calculated on a stand-alone basis were the set of costs not to be considered by the Board under the directions provided under the Separation Cost Provisions in assessing the no harm test. At page 12 the Board states:

> With respect to whether the costs to be considered in this analysis are incremental, fully burdened costs or some other level of costs, the Board is of the view that, in general, the fully burdened cost standard is appropriate in the context of applying the no harm test in the circumstances of the Application. The provisions of the legislation outlined in section 3.2.1 of this Decision support the ability of ATCO to use its discretion in appointing a

> party to carry out the Regulated Retail Functions. The legislation also contemplates and permits the possible separation of the distribution and Regulated Retail Functions. Accordingly, it is the Board view that the Separation Cost Provisions should be applied in the context of costs arising from the form of separation of the distribution and Regulated Retail Functions chosen by ATCO

A secondary legislative issue considered by the parties related to the use by DEML of a business unit, DERS, to perform the regulated retail functions. HVAC and the Consumer Group argued that DERS is a business unit of DEML and therefore, in and of itself, is not a "person" under the applicable legislation and that since the approval under subsection 3(2) of the *DGS Regulation* may only be granted to a DSP who in turn must be a "person" at law, DERS should be required to become a legally recognized person, distinct from DEML and its unregulated retailer.

DERS argued that HVAC's arguments on this point were inconsequential given that the Retail Sale Application contemplated that the regulated retail service function would be retained within DEML and that the unregulated function would be assigned to an affiliate. DERS, as a business unit of DEML, noted that it was part of DEML and argued that the Board had previously accepted this type of structure in Decision 2001-97 concerning ATCO Pipelines South, 2001/2002 GRA, Phases I and II.

The Board finds the analogy to the various business units of ATCO Gas and Pipelines Ltd. useful to the present Application. Establishing DERS as a business unit of DEML is a matter of convenience to DEML, however, it is DEML itself, as the legal entity, which bears all of the rights, obligations and responsibilities of DERS, and the Board shall hold DEML accountable in respect of those obligations and responsibilities. The fact that DEML has elected to create a business unit, through which it is intending to carry out the regulated retail functions, is not in the Board view a critical failure under the legislation to the Application.

## 2.3 Test Periods

DERS initially proposed a 5-month test period from August 1, 2003 to December 31, 2003 followed by a 12-month test period from January 1, 2004 to December 31, 2004. DERS subsequently amended its expected implementation[21] date from August 1, 2003 to December 1, 2003 and altered its proposed test periods to the 5-month period from December 1, 2003 to April 30, 2004 and the 12-month period from May 1, 2004 to April 30, 2005.

Even if the December 1, 2003 implementation date was not achieved, DERS still proposed to maintain an initial 5-month test period followed by a 12-month test period. DERS indicated that it would transition to a calendar year test period in its next DRT and RRT applications.

### Views of the Interveners

### AUMA/CE

AUMA/CE disagreed with DERS's proposed 5 and 12-month test periods. AUMA/CE submitted that final approval and implementation of DERS's DRT and RRT, assuming approval of the Retail Sale Application, was unlikely to take place before January 1, 2004 and given that likelihood, AUMA/CE recommended only one test period commencing January 1, 2004.

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[21] DERS noted that the earliest date projected for it to assume the ATCO Gas and ATCO Electric regulated retail functions was August 1, 2003.

In regard to DERS's commitment that subsequent test periods would be structured to coincide with a calendar year-end, AUMA/CE submitted there would still be issues with respect to piecing the monthly accounting and regulatory data back together to generate calendar year comparisons.

### Calgary

Calgary submitted that there was no pressing need for the test period for DERS to begin prior to January 1, 2004 and urged the Board to require DERS to maintain a calendar year-end for regulatory purposes. Calgary submitted that if the proposed sale transaction was approved, the Board should only allow a single test period ending December 31, 2004. Calgary argued that it was unnecessary to have an initial test period extend for more than a year since DERS would be a new DSP and with all the inherent uncertainty, a shorter rather than longer adjustment (review) period was essential.

Calgary noted that it was DERS's original intent to have test periods that coincided with a calendar year-end and that none of the DEML operating entities, nor parent companies, operated with fiscal years other than a calendar year. Calgary also noted that the fiscal year and test periods of the ATCO Utilities were based on calendar years.

Calgary submitted that when AltaLink Management Ltd (AltaLink) requested approval of non-calendar test periods in its recent GTA, the Board rejected the request and directed AltaLink to maintain regulatory records on a calendar year-end basis. Calgary argued that comparability, both inter-period and among utilities, was essential to test a rate application properly.

### Consumer Group

The Consumer Group disagreed with DERS's test period approach and argued that the proposed use of an arbitrary 5-month test period was without basis or merit. The Consumer Group noted that in the recent AltaLink decision[22] the Board rejected AltaLink's proposed use of a non-calendar year test period. The Consumer Group argued that the issue of comparability was as compelling in the case of DERS as it was with regard to AltaLink and that there was no basis or rationale to support an Alberta utility being out of sync with the normal gas and electric utility calendar test years, particularly when the other regulated retailers, EPCOR and ENMAX, were operating on calendar test years.

Consumer Group submitted that if the sales transaction was approved, there should be one calendar year 2004 test year for DERS. The Consumer Group submitted that should the commencement date be delayed beyond January 2004, the first test period should be shortened to cover the period ending December 31, 2004 in order to preserve calendar year regulatory reporting.

Consumer Group submitted that all other utilities under the Board's jurisdiction use a calendar year for financial and regulatory purposes and argued that DERS's suggestion to extend non-comparable data out to 2006 or 2007 was without merit and would result in unnecessary complication.

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[22] Decision 2003-061

### Views of DERS

DERS submitted that Board approval of the 5 and 12-month test periods would be appropriate for the following reasons:

- the original forecasts were thoroughly tested by the parties on a 5 and 12-month test period basis;
- the experience obtained over the 5 and 12-month test periods would provide more history than a 13-month test period and would permit DERS to apply for new tariffs that reflect the experience gained sooner than under a 25-month test period;
- subsequent test periods could be structured to coincide with a calendar year-end; and
- actual results could be restated on a calendar year basis for subsequent comparison, as monthly statements would be available.

DERS stated that it would be prepared to file audited financial statements on a test period and calendar year basis if required by the Board.

### Views of the Board

The Board notes that the initial test period for DERS cannot commence prior to January 1, 2004.

The Board agrees with the interveners that there are benefits to maintaining comparable test periods, both for inter-period comparisons and for inter-utility comparisons.

The Board has considered the reasons stated by DERS for implementing 5 and 12-month test periods, but believes it would be more beneficial to all parties if DERS implements a test period that ends on the calendar year-end.

The Board also notes that DERS's revenue requirement forecast for its proposed 12-month test period was based on calendar 2004 data.

Therefore, the Board considers that DERS's initial test period for the DRT and RRT should end on December 31, 2004.

## 2.4 I-Tek MS Agreement

DEML and ATCO I-Tek entered into a 10-year Master Services Agreement (MS Agreement) under which ATCO I-Tek will perform customer care services for DERS in respect of its RRT and DRT functions.

### Views of the Interveners

#### Ab-Com

Ab-Com submitted that when DERS argued against the use of a single database, DERS said in a roundabout way that a high price for regulated retail services was fundamental to DEML's decision to enter the Alberta market.

## ATCO

ATCO argued the regulations were clear and unambiguous. When considering whether an applied for cost – whether it be a "billing or other cost" – was just and reasonable, ATCO submitted that the Board was not permitted to have regard to overall increases in costs due to separation and unbundling. ATCO submitted that the Board must examine whether or not the Applicant justified the costs included in their own right, and should not examine the reasonableness of such costs by a comparison to what such costs were under the old legislative framework (pre-separation) and what they would be under the new legislative framework (post-separation).

ATCO noted there were suggestions that ATCO could provide billing on behalf of DERS and that a common database could be utilized. ATCO disagreed with that view. ATCO submitted such an approach would not be practical in light of the new legislative scheme, and would not further the policy objectives to be achieved by the Government of Alberta.

ATCO stated that DERS through its contract with ATCO I-Tek was adapting an existing successful billing process which was a known quantity (since it was very similar to that used by the ATCO utilities). ATCO suggested a different and untried approach, such as ATCO utilities providing billing service, and sharing access to a single database with DERS, was an approach that might not work and likely would be expense.

ATCO argued the responsibility for billing clearly rested with the RRP/DSP or retailer. ATCO noted the legislation allowed the distributor to be authorized to bill customers under the distribution tariff in certain circumstances. Accordingly, it would be permissible for ATCO and DERS to enter into an arrangement whereby ATCO performed the billing function on behalf of its appointee under the legislation.

ATCO submitted that the legislation explicitly provided that such arrangements were at the discretion of the distributor, not the Board. ATCO did not anticipate that it would be providing billing services under the new framework. ATCO also stated that even if such arrangements were feasible, it would not be appropriate or desirable for such arrangements to involve the use of a single database.

ATCO noted Mr. Hemstock's concerns regarding the *Code of Conduct Regulations* and confidentiality of customer information. ATCO shared some of those concerns, particularly given that its distribution customer base comprised more than just regulated rate customers who would receive service from DERS under the proposed arrangements. ATCO argued that two databases would ensure that confidentiality was maintained.

ATCO acknowledged the position put forth by Mr. Stephen that security could be handled by the technology inside of the database, and that he did not see the need, from an information technology point of view, to have to completely replicate and run on two different environments to ensure compliance. ATCO noted, however, that Mr. Stephens also acknowledged that costs would go up under that alternative.

Confidentiality concerns aside, ATCO was of the view that use of a single database and any economies that could be achieved would not be appropriate in light of the market structure and objectives to be achieved. ATCO submitted that the new legislative framework clearly delineated the roles and responsibilities of various market participants and explicitly assigned the billing function to the RRP/DSP. ATCO submitted that prudent costs associated with performing this function and all other RRP/DSP functions were therefore to be included in the RRT/DRT. ATCO considered that the intended result was complete and utter separation of functions, with the party appointed to perform the retail functions being required to bring forth its own stand-alone tariff for approval.

ATCO submitted that any suggestion that ATCO and DERS should utilize a single database, in an attempt to shelter regulated rate customers from these costs of restructuring, would be inconsistent with the new framework. ATCO submitted that permitting such cost savings to accrue to the benefit of the RRP would result in competitive retailers, who were burdened with the full cost of billing being placed at a competitive disadvantage.

ATCO noted that the MS Agreement was negotiated separately from the transaction documents regarding the transfer of retail functions. ATCO Gas and ATCO Electric were not privy to discussions between the parties and in no way influenced the outcome.

ATCO disagreed that the status quo would be maintained in the event that the proposed transaction did not proceed. ATCO argued true separation of the supply and distribution functions was required, and would be pursued by ATCO in the absence of the transaction with DERS.

In terms of the exception under the *Code of Conduct Regulation* that permitted the transfer by the distributor of information to the appointed regulated retail services provider, ATCO noted that it would not transfer information about customers not served by DERS. Therefore, the database used by ATCO would be different than that utilized by DERS.

**Calgary**

Calgary argued that while the Board was not asked to approve the ATCO I-Tek MS Agreement per se, because of the significant deleterious impact the agreement would have on the present consumers of ATCO, the cost consequences of the I-Tek MS Agreement must be vetted in full.

Calgary suggested that the Board was denied the benefit of valuable information due to the absence of ATCO I-Tek representatives at either the DERS or the Retail Sale hearings. Calgary argued that the ATCO I-Tek arrangement with DEML was an indirect way of lining the pockets of ATCO at the expense of the consumer. Calgary emphasized that the decision to contract as between DEML and ATCO vis-à-vis the ATCO I-Tek MS Agreement was strictly a business decision on the part of the parties and not a legislative requirement.

Calgary argued that the billing regulation permitted ATCO to prepare and distribute the bill in the one bill model as it was intending to do in the absence of the sale transaction.

Calgary argued the arrangement was entered into so that ATCO could increase its revenues from the deal and so that DEML could control the envelope/information flow. Calgary conceded that while the ATCO I-Tek MS Agreement deal from a substantive point of view may not be challengeable, it was clear that the same results could have been achieved without the extra costs that were being thrust upon the consumer by virtue of this application. Calgary argued the cost consequences to customers were excessive.

Calgary noted that DERS did not consider the use of a single database to be an option, and did not examine whether such a single database would even be feasible. Calgary argued that the enormous increase in billing costs were not required by legislation or technology.

Calgary submitted that the separation costs suggested by DERS would only be required if a company, in addition to being in the regulated business, was also in the unregulated business. Calgary concluded that if duplicate databases were required, the costs were the responsibility of DEP and not DERS.

Calgary argued that access to computer information could be managed by the security capabilities of the database system. Mr. Stephens testified that he did not see the need, from a technology point-of-view, to have to completely replicate the database and run on two different environments.

Calgary disagreed that the six price reviews would ensure that pricing remained market-based over the life of the agreement. Calgary argued the price reviews could be used up quickly for relatively minor changes such as the average handling time on inbound calls being reduced. Calgary also argued that neither DERS nor ATCO I-Tek would be incented to control costs due to the use of deferral accounts.

Calgary suggested that, while benchmarking was of considerable interest to many of the interveners in the hearing and that they considered benchmarking might be the solution to determining fair market value (FMV) pricing, Calgary was concerned that benchmarking might be difficult due to the abnormal packaging and pricing in the MS Agreement. Calgary submitted their concerns were well founded, and noted that Dr. Chwalowski could only identify three service providers that provided all the services that ATCO I-Tek did in North America (Alliance Data Systems, Orcom and Acenture). Calgary was of the opinion that 12 to 25 organizations should be part of any benchmarking study.

Calgary also submitted that any future ATCO I-Tek benchmarking study would not be a collaborative process that involved the utility, interveners, and the Board. Calgary suggested that was contrary to the approach adopted by the Board with regard to the ATCO I-Tek IT benchmarking. Although Calgary supported the use of a benchmarking process, Calgary argued it was a very difficult and non-scientific exercise; especially given the limited number of service providers who were available and their reluctance to participate.

### Consumer Group

The Consumer Group noted that the provision of customer care services to DERS and DEP by ATCO I-Tek was governed by the MS Agreement, and that the MS Agreement was negotiated by DEML as part of the overall sale of retail negotiations with ATCO. The Consumer Group also noted that no competitive bids were solicited for provision of customer care services.

The Consumer Group noted that the MS Agreement allowed for ATCO I-Tek to provide customer care services to DEML under an exclusive 10-year contract. The Consumer Group also noted that the MS Agreement provided for automatic price increases and the ability for either contracting party to require price reviews, based on benchmarking, three times during the 10-year period. The Consumer Group suggested that the costs negotiated under the MS

Agreement were expected to flow-through to DRT and RRT customers of DERS with little, if any, formal incentives on the part of DERS management to control those costs.

The Consumer Group submitted that considerable harm to customers would result from the duplication of customer databases and billing runs between the distributor and DSP.

The Consumer Group argued that DERS and ATCO misstated the consequences of a single database. The Consumer Group submitted that the purpose of a single database was not to reduce costs to regulated retail, but to reduce costs to distribution. The Consumer Group suggested there would be no un-level playing field for competitive retailers.

The Consumer Group advocated having a single database for distribution and regulated retail, with a security protocol that allowed appropriate use by both parties. Retail billing costs could be priced to give no advantage to the regulated retailer, yet savings could be passed onto distribution so customers receive the benefits of only one database and one billing run. The Consumer Group argued it was not using an incremental cost standard for the retailer, but rather allocating the incremental cost to the distributor.

In the Consumer Group's submission the focus of the prohibition on information sharing without customer consent in the *Code of Conduct Regulations* was between ATCO and DEP and/or between DERS and DEP. The Consumer Group considered that information shared between ATCO and its DSP (only) was not necessarily a danger as both were selling only regulated services and should not be using the customer information for marketing other services. As a result, the Consumer Group saw no foundation for DEML's position that the *Code of Conduct Regulations* necessitated the use of two databases for distribution and regulated retail.

The Consumer Group submitted that the larger problem addressed by *the Code of Conduct Regulations* was the exchange of information between ATCO I-Tek personnel representing DERS and ATCO I-Tek personnel representing DEP. The Consumer Group stated that was where a danger lurked and was where separate databases were required. The Consumer Group argued DERS's focus on separate databases for distribution and DERS was a red herring and resulted in significant and artificial customer costs.

### HVAC

HVAC noted that the MS Agreement contained provisions respecting the redetermination of prices through a mutually agreed upon benchmarking process. HVAC submitted that the benchmarking process was not mandatory, but rather both parties must first mutually agree to a benchmarking process as described in the Agreement take effect.

HVAC stated they did not object in principle to the use of a benchmarking process for the purposes of re-determining the value of services pursuant to a commercial agreement. However, HVAC was concerned that in these circumstances, and where clear business objectives existed by affiliates of DERS to grow the unregulated business as quickly as possible, it was reasonable to question whether DERS had the incentives necessary to ensure benchmarking studies attempted to realize lowest cost standards for required services.

HVAC argued that should the MS Agreement be found to be acceptable, the Board should maintain regulatory oversight of the price re-determination provisions. HVAC suggested parties could immediately be directed to prepare objective and independent benchmarking assessments, and direct when the next price re-determination benchmarking study should be completed.

**Views of DERS**

DERS submitted the MS Agreement was negotiated between the parties at arms length and that the agreed to pricing represented FMV for the customer care services and service levels to be provided. DEML submitted the decision to enter into the MS Agreement with ATCO I-Tek was based on the desire to have an established, experienced customer service provider as it aided a smooth transition and avoided problems that were experienced by other players in the Alberta marketplace. DEML argued the single source provided by ATCO I-Tek for call centre, billing and credit management functions also avoided the use of multiple service providers including those who did not have the Alberta market experience possessed by ATCO I-Tek.

DERS noted that Calgary suggested retail billing could be conducted by the distributor and result in cost savings. DERS stated that suggestion was addressed by DERS in its Retail Sale Argument.

DERS argued that the use of a single database was not an option available to DERS, and therefore it did not examine whether such a single database would even be feasible. DERS stated that separation of the regulated retail function from the distribution function was required by the new legislative regime and that complete separation could be achieved only if regulated retail energy services were provided on a stand-alone basis that reflected the fully burdened costs of providing this service.

DERS suggested it was clear from the Backgrounder to the Minister of Energy's August 21, 2003 News Release and the explicit language of section 5(b) of both the *RDS Regulation* and the *DGS Regulation* that the Government of Alberta contemplated that there would be an increase in billing costs arising from the separation of the regulated retail function and the distribution function.

DERS argued a level playing field was required in order to achieve the government's objective of continued development of a fair and competitive electricity and natural gas marketplace for consumers. DERS argued the purpose of utilizing a single database, if feasible, would be to reduce billing costs for regulated retail customers. If any cost savings associated with this were to accrue to the benefit of the RRP, DERS submitted that competitive retailers, burdened with the full cost of billing, would find themselves at a competitive disadvantage. DERS argued such a result would weaken, if not stifle, competition.

DERS stated the use of a single database would be more consistent with an incremental cost structure for the regulated retail billing function. DERS submitted the incremental cost standard was approved by the Board for ATCO Electric's RROT because the then existing RRO model was temporary, whereas the government has since replaced that model with the RRT, which is not temporary.

DERS submitted the MS Agreement permitted DERS to provide stand-alone customer care and billing services to its customers and that was consistent with the Government's policy objectives to provide a level playing field for competition and customer choice among regulated retail service providers and competitive retailers.

## Views of the Board

First, the Board notes that it is not approving the MS Agreement per se, but rather the Board will determine whether the service levels and costs resulting from the MS Agreement are fair and reasonable.

The Board will address the specific service levels and costs resulting from the MS Agreement, including the issue of benchmarking, in section 4.1.1.1.

In this section, the Board will address the broader issue of the separation of the billing systems and databases between the distribution function and the regulated rate function.

While the Board notes that DERS and ATCO suggest that the legislation mandates the separation of the distribution and the retail functions, the Board is not persuaded that the legislation mandates the separation of the distribution and RRP/DSP functions.

In the Board's view, there is nothing in the legislation that prohibits an owner of a distribution system from performing both the distribution and RRP/DSP functions, without any functional separation.

However, the Board also considers that the legislation permits the functional separation of the distribution and the RRP/DSP functions, and that the legislation recognizes that such separation could result in additional billing and other costs to customers.

Given that functional separation of the distribution and the RRP/DSP functions is permitted, the issue to be determined is whether it is reasonable and prudent to effect such a separation by using separate billing systems and separate databases.

Both ATCO and DERS submitted that separate billing systems and databases are required in order to create a level playing field between the RRP/DSP providers and competitive retailers. The Board considers that a level playing field between the RRP/DSP providers and competitive retailers with respect to billing costs would contribute to the development of a competitive market, consistent with the objectives of the legislation. However, the Board agrees with the Consumer Group that such a level playing field could likely be accomplished with a single billing system and database by allocating fully burdened costs to the RRT/DRT and allocating incremental costs to the distribution tariffs. The Board is not persuaded that the objective of a level playing field between the RRP/DSP providers and competitive retailers necessarily requires separate billing systems and databases.

With respect to the confidentiality of customer data, and the corresponding provisions of the *Code of Conduct Regulations*, the Board also agrees with the Consumer Group that concern regarding confidentiality arises between the distributor and competitive retailers, or between an RRP/DSP and competitive retailers. Despite ATCO's argument that not all distribution customers will be regulated rate customers, the Board does not consider that separate databases must be maintained to ensure confidentiality of customer information as between the distributor and the RRP/DSP. The Board notes the evidence of Mr. Stephens that to the extent there were confidentiality concerns between the distributor and the RRP/DSP, such concerns could be adequately addressed by the security capabilities of the database system.

Notwithstanding the above, the Board notes the evidence of ATCO that the ongoing requirements of the distributor and the RRP/DSP will be different, and the structure and the content of the billing systems and databases will diverge over time. The Board recognizes that customer billing systems and databases are very complex. Given that the legislation clearly permits the functional separation of the distribution and RRP/DSP functions, the Board does not consider it reasonable to expect that two separate companies, with differing requirements for complex systems, should be expected to collaborate on a single system and database that would meet all of the requirements for both companies.

The Board considers that by permitting the functional separation of the distribution and RRP/DSP functions, and by specifically recognizing that there could be incremental billing and other costs incurred by customers as a result of such separation, it would be inconsistent with the legislation to disallow the costs of separate billing systems and databases for the distribution and RRP/DSP functions.

However, the Board considers that any costs incurred must still be reasonable and prudent. The Board will address the specifics of such costs in section 4.1.1.1.

## 2.5 Cost of Credit Principles

DERS included credit support expenses in its revenue requirements for its RRT and DRT. DERS noted that credit support was required for the MS Agreement with ATCO I-Tek and for gas supply counterparties. DERS included credit support expenses for Letters of Credit and Parental Guarantees in its revenue requirements.

DERS noted that for the purposes of recovery under the 2004 RRT and DRT, the cost to obtain a Parental Guarantee would be calculated based on a charge of 0.4% per annum that would be paid to Centrica plc[23] pursuant to the Centrica Charging for Credit Policy.

DERS noted that a bank Letter of Credit was available to DEML at a rate currently negotiated at 62 1/2 basis points (bps). DERS also noted that in order to provide the Letter of Credit at 62 1/2 bps, the bank required a Parental Guarantee from Centrica plc.[24]

This section deals with the issue of whether DERS should be allowed to recover expenses associated with credit support arrangements. Sections 3.1.1.4, 4.1.1.4 and 4.2.2.2 deal with the specific items for which DERS requested credit support in its RRT or DRT revenue requirements.

### Views of the Interveners

### AUMA/CE

AUMA/CE submitted there would be no requirement for any guarantee from Centrica plc in respect of the ATCO I-Tek MS Agreement. With respect to the gas supply agreements, AUMA/CE submitted that there would be no need for a guarantee and possibly a requirement for a Letter of Credit from an approved financial institution, if Centrica plc contracted directly with gas suppliers. AUMA/CE submitted that Centrica plc's business arrangements or decision to designate DEML as the purchaser of the assets, created the opportunity for Centrica plc to provide a guarantee. Even though the parent, Centrica plc, has corporately decided to pass on the charges to DERS, AUMA/CE submitted that the Board should not be persuaded that these were reasonable costs that should be passed on further to regulated customers of DERS.

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[23] Centrica plc is the parent of DERS.

[24] Tr. p. 1152

AUMA/CE submitted that DERS had not shown that there would be any impairment of Centrica's ability to raise capital and argued that Dr. Foster had to acknowledge that if the Board disallowed the credit charges to be passed through to the ratepayers of DERS, there would be no change in the liquidity of Centrica or its cost of borrowing.

AUMA/CE submitted that Dr. Foster confirmed that the other unregulated business units of DEML were subject to greater risks than DERS and argued that if the Board determined that a guarantee credit charge was appropriate, the guarantee rate for the less risky DERS business unit should be no higher than 30 bps. If DERS was awarded any credit charges for Parental Guarantees, AUMA/CE submitted that DEML should be directed to provide a third party commissioned risk analysis report detailing the credit risk differences and costs between the regulated and unregulated businesses of Centrica at its next tariff application.

AUMA/CE argued that other than some Letter of Credit charges to support gas purchases, most of the charges were opportunity costs created by Centrica plc.

### Calgary

Calgary submitted that there was no impairment or contingent liability for Parental Guarantees or Letters of Credit that would impact Centrica plc's ability to engage in other activities and argued that there was no cost to Centrica plc in providing a Parental Guarantee or a Letter of Credit. Therefore, Calgary submitted that DERS should not pay an amount to Centrica plc.

Calgary submitted that the amount that DERS proposed to charge for Parental Guarantees and Letters of Credit appeared to be just another way of charging a rate of return. Calgary stated that customers have not had the opportunity to examine the financial viability of DEML and have had limited information with respect to its division DERS.

With respect to AE Decision 2002-85, Calgary submitted that the Board indicated that it was not embracing the concept that the Parental Guarantees or Letters of Credit impair the ability of the parent to invest in non-regulated opportunities. Calgary argued that even if the Board reversed its' ruling and decided that evidence of impairment should be passed onto consumers, there was absolutely no evidence of an impairment in this particular case.

Calgary submitted that the cost to provide credit facilities was being charged across the board by Centrica plc to all its' subsidiaries and business units, without regard to the extent to which, if any, those individual business units or subsidiaries were the cause for the credit charges.

### Consumer Group

The Consumer Group submitted that the Parental Guarantee charge applied to all Centrica plc subsidiaries and argued that it reflected a composite risk evaluation for all regulated and non-regulated entities. The Consumer Group submitted that since the risk profile of regulated business units would be less than the composite risk, it followed that the composite rate charged to regulated units would be overstated. Pending supporting evidence in a later test year, the

Consumer Group suggested that the Board only approve 50% of the requested rate, or 0.20% to account for the regulated/non-regulated disparity.

The Consumer Group submitted that there was a lack of direct precedent for including the cost of credit support as a component of revenue requirements in Alberta.

The Consumer Group argued that the Board's findings on deemed income tax expense in AltaLink Decision 2003-061[25] were germane to the issue of credit support costs because both involved deemed expenses from a parent and neither had a reasonable expectation of actually occurring. The Consumer Group submitted that the forecast DERS credit charges should not be included in the utility revenue requirement unless there was a reasonable expectation they would be incurred.

The Consumer Group was concerned that approval of a credit charge from Centrica plc would not be subject to regulatory scrutiny with comparison to actual charges, incurred by the parent and argued that the DERS proposal would allow credit charges to be simply set on an ad-hoc basis by Centrica plc for all subsidiaries and without consideration of the level of risk for these subsidiaries.

The Consumer Group submitted that like AltaLink, the Application does not allow for access to actual costs of a previous regulatory period and without the provision of Centrica plc financial statements and pro-forma statements before and after the proposed transaction, there was no way to assess the impact and incremental credit costs attributable to DEML and DERS.

In addition, the Consumer Group submitted that since such credit charge estimates were subject to estimates of volumes and prices, it was essential that any credit charges be subject to deferral account treatment with prudence checks on a monthly basis.

The Consumer Group also submitted that Letters of Credit should be subject to an RFP process to ensure customers are receiving the lowest cost commensurate with requirements.

### Views of DERS

DERS stated that the purpose of the Centrica Charging for Credit Policy was to recognize the cost of credit and credit procurement activities of Centrica plc and charge these costs directly to all Centrica plc business units. DERS submitted that the rationale for the policy was to ensure the operations of all business units reflected the reality that Centrica plc has finite capital and financial resources and that it incurs a cost when it provides parental credit support to its business units.

DERS submitted that the cost of the Parental Guarantees, set at 40 bps, reflects the actual cost to DERS as charged by Centrica plc to all business units for the support provided by the parent organization. DERS argued that the rate was reflective of the cost of credit to Centrica plc for a credit facility negotiated with an independent third party and was lower than the current market rate if such a facility were negotiated today. DERS argued that the low rate for this charge reflected Centrica plc's Standard and Poor's "A" credit rating and its Moody's "A2" credit rating and it also reflected the considerable volume of investment and commercial banking business Centrica plc undertakes.

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[25] Decision 2003-061 – AltaLink Management Ltd., and TransAlta Utilities Corporation Transmission Tariffs for May 1, 2002 to April 30, 2004 and TransAlta Utilities Corporation Transmission Tariffs for January 1, 2002 to April 30, 2003, dated August 3, 2003

DERS noted that Centrica plc's financing and borrowing costs fluctuate with the market, and the charges in the policy are reviewed annually and may be adjusted to reflect the cost to Centrica plc of securing similar lending facilities, including Letters of Credit, at the time of the review.

DERS submitted that the cost of credit required to support the business needs of DERS was a true cost. DERS stated that the issue of compensation for the use of a company's balance sheet was addressed by the Board in ATCO Electric's 2002 RRO Application and DERS submitted that the Board considered that there was merit in consideration of the cost of ATCO Electric providing added value to customers, but that additional evidence was required on both cost justification and the level of such cost. DERS argued that it provided considerable evidence supporting both the requirement for and the cost of Parental Guarantees.

DERS submitted that strong credit backing was required in today's energy market to support the acquisition of gas supplies. DERS stated that the provision of Parental Guarantees by Centrica plc would allow DERS to avoid posting Letters of Credit with gas supply counterparties. DERS submitted that the cost associated with obtaining Letters of Credit from financial institutions would be at a higher cost than the 40 bps charged under the Centrica Charging for Credit policy and would in any event first require the posting of Parental Guarantees with those financial institutions. DERS argued that the provision of Parental Guarantees would typically avoid the cost associated with having to post Letters of Credit. DERS stated that the exception to DERS's ability to avoid posting Letters of Credit was in the case of gas supplies acquired on the Natural Gas Exchange (NGX) because the NGX required a Letter of Credit from an approved financial institution.

DERS noted that the forecast cost of Letters of Credit included in the Application was 62.5 bps and argued that this was well within the range of the cost of Letters of Credit for companies with superior credit ratings.

DERS argued that the cost of Letters of Credit was the actual cost that would be incurred to obtain these Letters of Credit from financial institutions and that the cost of Parental Guarantees reflected an actual cost imposed by capital markets to recognize the effect on creditworthiness and liquidity of providing Parental Guarantees. DERS submitted that these costs would necessarily be incurred on behalf of regulated customers and argued that it was appropriate that these costs be recovered through rates to be charged to those customers.

DERS argued that if Centrica's cost of credit increased, Calgary would claim that the increase was unrelated to the activities of DERS and the issuance of Parental Guarantees to DERS's suppliers. DERS submitted that this would be very difficult for DERS to prove and in any case too late to recover from the regulated customers and therefore, DERS sought the expert witness of Dr. Foster.

DERS submitted that it cannot be disputed that there is a cost of credit associated with the procurement of gas. DERS argued that the use of Parental Guarantees represented the lowest cost alternative for regulated customers and if the Board decided not to approve the recovery of costs associated with Letters of Credit and Centrica's Parental Guarantee, DERS would be forced to examine alternatives for the financing of its supply requirements; the options being the prepayment of gas through working capital, or establishment of a standalone (without Parental Guarantee support) credit facility to issue letters of credit. DERS submitted that this will afford the transparency sought by Calgary, but it would also cause an increase in DERS's revenue requirement compared to what has been applied for in the Application.

### Views of the Board

In this section, the Board will determine whether DERS should be allowed to recover expenses associated with credit support. In addition, the Board will consider the level of credit support costs, if any, to be recovered.

The Board notes that AUMA/CE submitted that credit support would not have been needed if Centrica plc had purchased the retail assets of ATCO, and that credit support would have been minimized if Centrica plc contracted directly with gas suppliers. The Board agrees that this may be true, however, as noted in section 2.2 in this decision, the Board considers the appropriate standard to be applied in considering the prudence and reasonableness of such costs is the stand-alone cost standard, and the Board does not consider it necessary in the circumstances to consider what alternative structures could have been implemented.

The Board notes that two forms of credit support were discussed in this proceeding: Parental Guarantees and Letters of Credit. The Board also notes that DERS and Calgary made reference to ATCO Electric's 2002 RRO Application which discussed these two forms of credit support. The Board considers the following excerpts from the ATCO Electric decision to be relevant to the current circumstances.

> Further, the Board notes that if AE had, in fact, purchased the Letters of Credit rather than presenting their avoided costs and the Board determined that the purchase was prudent, then the issue would be approached from a different basis. The amount would then not be in question as much as the appropriateness of or need for the costs. However, none of the recovered costs would flow to AE's shareholders, but instead all would be used to cover the actual costs incurred for the letters.
>
> In the event that the Board is convinced in a future proceeding that the ATCO Group adds value through the use of their balance sheet to avoid costs for RRO customers, the Board might consider that a portion of the avoided costs should be treated as a value added service and should be paid to AE through an RRO management fee.[26]

With respect to Letters of Credit, the Board notes that DERS's forecast cost of Letters of Credit was 62 1/2 bps.[27] The Board also notes that no intervener provided evidence that this rate was unreasonable.

With respect to the issue of compensation for use of a company's balance sheet, the Board notes that DERS and interveners did not agree on the impact to Centrica plc of issuing a Parental Guarantee. The Board notes that DERS stated that for the 2004 test period it would pay Centrica plc 0.4% per annum, and that the 40 bps charge was based on the cost to Centrica plc of securing a committed lending facility from one of its primary relationship banks in 2001. The Board also notes that, in the event that the Board approved the use of the Parental Guarantee charge,

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[26] Decision 2002-085, p. 46

[27] The Board notes that the Letter of Credit cost usually reflects a fee paid to a financial institution for standing by with cash to reimburse the beneficiary of the Letter of Credit.

AUMA/CE and the Consumer Group argued that the charge should be no higher than 30 bps and 20 bps respectively. The Board also notes there was no evidence in the proceeding that challenged DERS's assertion that the 40 bps charge was lower than the current market rate for a credit facility that could be established for Centrica plc with an independent third party.

Although the Board considers that it would have been of assistance to have had more evidence on the opportunity cost or credit impacts to Centrica plc of extending Parental Guarantees to DERS, the Board does not see this deficiency as necessarily fatal to inclusion of reasonably incurred credit charges paid to Centrica plc by DERS to obtain Parental Guarantees where the charges associated with these Parental Guarantees are lower than the financing costs that DERS would otherwise incur. In Decision 2002-085, the Board considered it significant that prior to the separation of the RRO function, ATCO Electric had been providing a bundled distribution function and regulated retail function and had been receiving a bundled return on its investment. The Board did not consider it appropriate in the circumstances that the unbundling of the RRO function should result in additional compensation for ATCO Electric when it continued to provide the same services it had prior to the unbundling, albeit in a different form. In the Application, DERS is providing the regulated retail function on a stand-alone basis, without a rate base and associated return. These circumstances clearly distinguish the situation under which DERS provides the unbundled regulated retail function from the situation under which ATCO Electric provided the regulated retail function. Accordingly, the Board considers it appropriate to reimburse DERS for reasonably incurred costs associated with obtaining Parental Guarantees, costs it incurs on a stand-alone basis that are lower than the financing costs it would otherwise have incurred without the benefit of the Parental Guarantee, resulting in overall lower costs for RRT and DRT customers.

Given that the proposed Parental Guarantee charge is lower than the forecast cost of a Letter of Credit, the Board considers that Centrica plc would provide value through the use of its balance sheet in situations where the Board considers the credit support requirements for a particular contractual arrangement are reasonable and where a Parental Guarantee can be used instead of a Letter of Credit.

Therefore, the Board considers that DERS should be able to recover the 40 bps Parental Guarantee charges in the approved test period through the DRT and RRT with respect to those situations described in this Decision where the Board determines that the credit support requirements for a particular contractual arrangement are reasonable and the actual cost that would be incurred to obtain a Letter of Credit from a financial institution would be greater than 40 bps. In this proceeding, DERS has identified requirements for credit support in sections 3.1.1.4, 4.1.1.4 and 4.2.2.2. The Board also notes DERS's comment that in some situations, counterparties will not or may not accept Parental Guarantees. In this situation, if the Board determines that the credit support requirements for a particular contractual arrangement are prudent, the Board will allow the recovery of actual costs associated with the Letter of Credit and additional Parental Guarantee charges, if required to support the Letter of Credit. However, the Board expects DERS to negotiate in good faith on behalf of ratepayers and try to minimize credit support expenses.

## 2.6 Cost of Working Capital

Working capital can be defined as follows:

> Cash and other quick assets. In accounting the difference between current assets and current liabilities. In public utilities the amount of cash required by a business to carry on operations.[28]

The need for working capital results from the lag between the rendition of service and receipt of payment. The cost of working capital represents the amount of interest needed to compensate a lender for the use of the funds involved. For a rate base utility, an allowance for working capital is included in its rate base so that investors are compensated for capital they have provided to the utility.

A utility is allowed a rate of return determined in reference to its rate base. The general basis on which an authorized rate of return is established is the utilities cost of capital, which refers to the costs incurred by the utility in obtaining various sources of approved funding and financing (usually consisting of the issuance of various sources of securities such as long-term debt and shares). To carry out the role of the DSP or RRP, DERS does not require a rate base but does require working capital, in respect thereof DERS requested approval of an interest rate of 10% for forecasting purposes. DERS stated that its source of financing would be from Centrica plc, its ultimate parent company, which would be charging DERS 12% on inter-company advances. For purposes of the RRT and DRT, DERS proposed that working capital would be included in deferral accounts wherein differences between forecast and actual costs will be accrued and reconciled annually.

### Views of the Interveners

### AUMA/CE

AUMA/CE stated that DEML neglected to mention that the type of working capital related to the DSP functions does not require long-term financing. AUMA/CE submitted that there was no evidence that Centrica will go to the debt markets to purchase securities to cover working capital. AUMA/CE further submitted that long-term financing is taken out to finance purchase of long-term assets and "inter-company" loans from Centrica should not be viewed as the equivalent of long-term financing.

AUMA/CE stated that DERS requested a rate of 10% on its working capital requirements based on the rationale that the rate was related to Board comments in Decision 2000-88 and attempted to further justify the rate on the basis that Centrica has a weighted average cost of capital of 12%.

AUMA/CE argued that the asserted average cost of capital of Centrica was irrelevant to any justification for a 10% rate for two reasons:

- the 12% rate was untested in any regulatory forum;
- there was no evidence demonstrating that long-term debt, additional equity or preferred shares were issued by Centrica to support DERS's working capital.

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[28] Black's Law Dictionary, Fifth Edition

AUMA/CE also disagreed with DERS's position that the rate of 10% was justified based on a consideration that the working capital is a long-term asset or alternatively, that the use of debt to finance working capital would increase the risk too much to DERS. AUMA/CE supported the recommended working capital cost rate of between 3.5% and 4% proposed by Calgary because the use of working capital for the DERS retail service is financed and can be financed from short-term debt.

**Calgary**

Calgary submitted that both the 10% and 12% rates referred to by DERS were without foundation in regulatory economics and generally accepted regulatory practice. Calgary argued that those rates did not reflect rates that could be seen in the market place and were excessive in comparison to the weighted average cost of capital that will likely result from the generic cost of capital proceeding[29] that is currently before the Board.

Calgary disagreed with DERS's position that working capital is a long-term asset or a perpetual asset. In opposing this notion Calgary noted that:

- DERS's proforma balance sheets showed only current assets and current liabilities;
- being current accounts, accounts receivable and accounts payable go through a continuing cycle in a year;
- inter-company amounts ("due to parent") will be used to finance DERS's working capital;
- the due to parent amounts have no specific terms of repayment, have no requirements for maturities beyond 12 months, and are due "on demand", which is indicative of short-term financing to which short-term rates should apply; and
- fluctuations in the balances and the potential for changes in the number of customers would indicate that use of long-term financing may be excessive and therefore imprudent.

Calgary noted that DERS, unlike other utilities, will not have a rate base and has not had to justify its capital structure.

Calgary was concerned that there was a lack of knowledge on how DEML was to be financed. Had this knowledge been available, Calgary suggested that parties might have come to different conclusions regarding short-term and long-term financing.

Calgary also disagreed with DERS's reliance on Decision 2000-88,[30] which dealt with ATCO Electric's 2001 RROT Non-Energy Cost Application, as a basis to use 10% as an appropriate cost of working capital. Calgary noted that:

- the Decision was interim;
- the 10% rate was not tested;

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[29] Application No. 1271597

[30] Decision 2000-88 – ATCO Electric Ltd., Regulated Rate Option Tariff, Part B: Non Energy Cost Component, dated December 22, 2000

- ATCO's working capital amount of concern was substantially less than the requirement forecast by DERS;
- the legislation is placing permanence on the DRT and RRT, whereas the RRO was a temporary measure; and
- the Board determined that daily shortfalls and excesses used to calculate ATCO's working capital should be collected in a deferral account and financed using the rate from the Board's General Policy for Payment of Interest (IL 2000-1).

Calgary submitted that it was not feasible to assume the direction regarding carrying costs in Decision 2000-88, given the circumstances that existed at the time, should apply to the carrying costs in this proceeding.

Calgary concluded that as the nature of the assets being financed was short-term, the related financing should also be short-term. Calgary recommended that the cost of working capital should be reflective of borrowing for short-term capital and be in the range of 3.5% to 4.0%.

**Consumer Group**

The Consumer Group noted that, in accordance with the principle set out in section 90(2)(b) of the *Public Utilities Board Act*, R.S.A. 2000, c. P-45 (PUB Act) and also in section 37(2) (b) of the GUA, regulated utilities have been allowed to include an allowance for Necessary Working Capital (NWC) in rate base and to earn the same return on NWC as fixed assets in rate base. The Consumer Group agreed the cost of NWC is a legitimate expense for DERS to recover through rates in the event the Board approves DERS's appointment as DSP and RRP for the ATCO Gas and ATCO Electric service territories.

With respect to the cost to be applied to NWC, the Consumer Group noted that DERS relied on Decision 2000-88 as the basis for its proposed 10% cost of capital for NWC requirements. The Consumer Group agreed with Calgary's evidence that suggested subsequent events and decisions may have superseded the reasoning in Decision 2000-88 and that the Decision would not therefore be applicable to the circumstances set out in the Application.

The Consumer Group argued that, for non-energy NWC costs, such as operating costs, neither the proposed 10%, nor alternative 12%, represented prudent business costs and that there was no evidence indicating or substantiating the derivation of either rate. The Consumer Group submitted the proper cost rate to use would be the actual financing arrangement put in place for working capital.

The Consumer Group did not agree with DERS's proposition that working capital is a long-term asset and requires some equity underpinning. The Consumer Group submitted that if the Board was persuaded some equity underpinning would be required, the Board's determination in Decision 2001-92[31] concerning financing of pool price deferral accounts should be used. The Consumer Group noted, as in the case of financing of Pool Price deferral accounts, the risk associated with recovery of DERS's working capital would be very low given all amounts would be trued up to actual through deferral accounts. The Consumer Group argued that any deemed equity amount should not be a purely deemed amount, but it should actually be reflected in DERS's balance sheet.

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[31] Decision 2001-92 – 2002 Pool Price Deferral Accounts Proceeding, Part K: Recovery Period, Carrying Cost Rates, Collection Issues and Hedging, dated December 12, 2002

### Views of DERS

DERS stated that the "due to parent" shown on its balance sheet was the working capital. DERS confirmed that in each month, there is an interest amount due to the parent in respect of that working capital. From DERS's perspective, working capital was an inter-company loan and it looks just like an interest expense.

DERS submitted that it used an interest rate of 10% when calculating the working capital costs, in accordance with the rate prescribed by the Board in Decision 2000-88, which pertained to ATCO Electric's 2001 RROT Non-Energy Cost Application. DERS noted that the Board also directed the use of the 10% interest rate for working capital requirements in Decision 2002-85, which concerned ATCO Electric's 2002 Non-Energy Cost Application. DERS further noted that rate would be applied to working capital requirements net of the amount of customer deposits it will hold. This offset will benefit all customers by reducing the cost of working capital in the revenue requirement.

DERS argued that Calgary was wrong in asserting that the interim nature of Decision 2000-88 could have influenced the Board's direction concerning the use of the 10% rate. DERS submitted:

- the 10% rate was used for determining ATCO Electric's working capital requirements for final 2001 RROT rates and indeed, the Board reiterated the use of the 10% for final rates for ATCO Electric's 2002 RROT;
- Calgary's reliance on the smaller amount of ATCO Electric's working capital requirement as support for the Board's approval of the 10% rate for ATCO Electric was nothing more than speculation because the Board did not suggest that the size of the working capital requirement affected its decision to direct the use of the 10% rate in Decision 2000-88 or Decision 2002-85;
- IL 2000-1 addresses the interest rate to be paid or received by a utility in respect of rate adjustments;
- the 10%would be applicable on a forecast basis and in respect of any adjustments to working capital outside of that forecast, IL 2000-1 would apply; and
- the directed use of the rate prescribed in IL 2000-1 by ATCO Electric in respect of working capital adjustments in the deferral account was consistent with the purpose of that IL and does not in any way indicate that 10% is an inappropriate rate to be applied to DERS's forecast working capital requirements.

DERS submitted that Calgary was also wrong in its assertion that DERS's forecast working capital was almost entirely based on short-term amounts and therefore should be financed based on short-term instruments. DERS argued that working capital is a long-term asset and should be funded by a long-term capital structure because there will always be a requirement for working capital. DERS stated that there is a requirement for Centrica to inject working capital into DERS.

DERS submitted that use of debt only (short-term or long-term) financing injects too much risk into the organization, as it is not sustainable to finance assets on a debt only basis over time. DERS noted that in past Board decisions, other regulated entities have included working capital as part of their rate base, thereby financing that working capital through debt and equity.

DERS noted that Centrica will charge DERS 12%, which was based on its weighted average cost of capital. DERS suggested that, from Centrica's perspective, the reason the 12% working or weighted average cost of capital was used for debt equity purposes was that it does not want cherry picking of certain assets and various financing arrangements for certain assets. DERS submitted that it could not isolate one asset for financing purposes and that any financing has to be undertaken in reference to the overall corporate financing plan.

DERS concluded that it was not seeking recovery of the difference between the 10% applied-for rate and the 12% weighted average cost of capital charged by the parent. DERS submitted that Calgary's assertion that working capital should be financed on short-term instruments was without foundation and was inappropriate because it ignored the long-term nature of the working capital requirement and the need for a debt/equity capital structure that has been traditionally used to finance the working capital requirements of entities that are rate regulated by the Board. For those reasons, DERS submitted that it would be appropriate for the Board to approve the applied-for 10% rate.

**Views of the Board**

The Board notes that, as set out in section 90(2) of the PUB Act, the Board is required to fix a fair return on rate base, and rate base is defined to include necessary working capital. Thus, working capital has to date been financed at the same weighted average cost of capital as all other components of rate base.

This Application is unique in that it is the first application to the Board that includes a requirement for working capital, but no other component of rate base.

Although the accounting definition of working capital is the difference between current assets and current liabilities, the Board recognizes that the requirement for working capital is an ongoing requirement. The Board is therefore not persuaded that working capital requirements would be financed on an ongoing basis using only short-term debt.

On the other hand, the Board is also not convinced that, for an entity with no other component of rate base, it is necessary to finance working capital using only long-term debt and equity as has traditionally been applied to rate base.

The Board is also cognizant of the relatively small amount of working capital requirements called for in the current Application, and the Board considers that it would not be appropriate to incur significant regulatory costs to establish a capital structure and a rate of return on common equity for DERS.

The Board does not consider the weighted average cost of capital of Centrica plc to be relevant to this decision. Recognizing that DERS is proposing to fulfill its RRP/DSP functions on a non-profit basis, the Board considers that DERS should be entitled to recover its actual costs of working capital on a stand-alone basis.

The Board is not persuaded that the 10% rate allowed by the Board for ATCO's working capital requirements in Decisions 2000-88 and 2002-85 is necessarily an appropriate precedent for DERS. The Board notes that among other things income tax rates have fallen since 2000 and, unlike ATCO, DERS has mitigated much of its risk through the use of deferral accounts.

The Board notes the suggestion of the Consumer Group that the Board could use a 15% equity ratio as was the case in the financing of the Pool Price Deferral accounts. However, the Board is also not persuaded that the financing of the Pool Price Deferral accounts is an appropriate precedent, given the securitization of that financing and given the fixed, relatively short, repayment period for the deferral amounts.

The Board is concerned that there is no evidence on the record as to what the actual costs of working capital to DERS would be on a stand-alone basis.

The Board directs DERS to demonstrate at the time of its next DRT and RRT non-energy applications what its cost of providing working capital would be if it obtained its working capital through a financial institution, on a stand-alone basis with a parental guarantee.

The Board is not persuaded that 10% is a reasonable rate to be applied to DERS's working capital requirements. On the other hand, the Board is also not persuaded that DERS could finance its entire working capital requirements at short-term debt rates in the range of the 3.5-4% recommended by Calgary. Therefore, for the purposes of this decision, recognizing the lack of information on the record as to what DERS's stand-alone costs of financing working capital would be or the financing costs that would be incurred by a similarly situated regulated service provider without rate base, the Board will allow a cost of working capital of 8.5%.

For the purposes of the DRT and RRT working capital deferral accounts, the Board considers that it would be appropriate to apply the allowed rate of 8.5% to both the forecast and actual working capital amounts.

## 2.7 Integration and Delay Costs

DERS indicated that there would be integration costs associated with the Application. Integration costs refer to the capital and operating costs required to set-up and implement the stand-alone billing, accounting and customer care systems, installation of information systems, and the preparation of the tariff application.

In the Application, DERS had planned an August 1, 2003 implementation date for the DRT and RRT and the related integration costs are shown in Table 1. Later, DERS indicated that the August 1 date had been revised to December 1, 2003 and that delay costs would also be included in the RRT and DRT. Table 2 shows the integration and delay costs assuming that DERS would begin RRT and DRT operations December 1, 2003.[32]

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[32] Exhibit 005-40

Table 1. Total Integration Costs – August 1, 2003 Implementation

| | Capital Costs ($ 000) | Operating Costs ($ 000) | Total ($ 000) |
|---|---|---|---|
| DRT Function | 6,108 | 1,893 | 8,001 |
| RRT Function | 3,240 | 375 | 3,615 |
| Total | 9,348 | 2,268 | 11,616 |

Table 2. Total Integration and Delay Costs – December 1, 2003 Implementation

| | Capital Costs ($ 000) | Operating Costs ($ 000) | Total ($ 000) |
|---|---|---|---|
| DRT Function | 6,003 | 3,479 | 9,482 |
| RRT Function | 3,239 | 856 | 4,095 |
| Total | 9,242 | 4,335 | 13,577 |

DEML also indicated that the monthly delay costs after December 1, 2003 would be $433,000 for the DRT and $141,000 for the RRT.

### Views of the Interveners

#### Ab-Com

Ab-Com noted DERS's argument that the regulated customers should bear the full integration costs of setting up its new, unregulated business in Alberta. Ab-Com considered that these costs were much higher than necessary and should not be covered by the regulated customers.

#### AUMA/CE

AUMA/CE considered that DERS in essence confirmed there was no legislation enabling the Board to award integration costs or delay costs to either the gas or electric retail functions of DERS until such time that the Board granted permission for DERS to be the DSP or an owner under the electric regulations to provide the regulated electricity services.

AUMA/CE noted that DERS also acknowledged that the integration costs as defined by DERS were not included in either the *DGS Regulation* or the *RDS Regulation*. Further, AUMA/CE submitted that section 103 of the EUA SA 2003 only applied to an owner of an electric distribution system with respect to preparing a regulated rate tariff. Given that DERS was not an "owner," the AUMA/CE submitted that the EUA was of no assistance to enable DERS to recover any integration costs or delay costs.

Further, AUMA/CE submitted that sections 3 and 5 of the *DGS Regulation* apply to the setting of the gas DRT for a DSP and argued that DERS was not a DSP since Board approval was not yet obtained. Therefore, AUMA/CE submitted that the *DGS Regulation* was of no assistance to enable DERS to recover any integration costs or delay costs.

AUMA/CE submitted that the Board does not have jurisdiction to award any integration costs or delay costs to DERS and argued that if the Board approved the appointment designation of DERS as the DRT and RRT providers, then the Board may consider allowing the necessary and prudently incurred capital costs required for the provision of the DRT and RRT services. AUMA/CE argued that since the Board does not have the jurisdiction to award any integration costs or delay costs prior to DERS commencing operations as the DRT or RRT provider, any costs that DERS incurs to set-up the business to provide these services should be borne by DEML's shareholders.

AUMA/CE noted the OEB criteria used by DERS to justify the integration and delay costs and submitted that the majority of the costs to upgrade existing systems of DEML were currently used by the EMG business unit or ATCO I-Tek and should not be included. AUMA/CE argued that the delay costs should not qualify as transition costs using the OEB criteria.

AUMA/CE submitted that DERS did not provide any quantitative analyses of the alternatives it examined for the options available to provide various components of retail services and argued that even if the OEB criteria applied, DERS has not passed the OEB criteria for approval of its transition or integration costs and delay costs.

AUMA/CE submitted that by May 2003, DERS knew that an implementation date of August 1, 2003 was not achievable and argued that DERS should have mitigated any delay costs incurred after May 30, 2003. AUMA/CE stated that DERS should not recover any Corporate costs incurred after August 1, 2003 since they were simply a pass down of costs that would be incurred regardless of whether DERS had commenced operations or not.

AUMA/CE noted that DEML considered that certain regulations gave the Board authority to award integration costs and delay costs.

AUMA/CE argued that these regulations do not enable the Board to award costs to a party that has not yet received a Board approved and recognized RRP status.

AUMA/CE submitted that the legislation and subordinate regulations do not envisage awarding any costs of operation, whether prudently incurred or not, prior to receiving recognized status from the Board as a RRP.

AUMA/CE noted the DEML argument that it would not be practical or make sense to expect DEML to bear these costs and have them end up as "stranded" costs.[33] AUMA/CE argued that common sense dictates that this was an arms-length negotiated transaction between sophisticated parties and that these costs could and should have been factored into the "arms length" negotiations of the sale price.

AUMA/CE reviewed the DRT and RRT operating related integrations costs and supporting evidence, and proposed that the operating integration costs be adjusted as follows:

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[33] DEML Argument, pp. 25 – 26

Table 3. DRT Operating Related Integration Costs Change

| | |
|---|---|
| $1,893,000 | Original – Schedule 6.4 |
| **LESS** | |
| $147,000 | Change to August, 2003 costs[34] |
| $630,000 | Regulatory included in Hearing costs |
| **PLUS** | |
| $89,000 | Additional Regulatory staff costs |
| **$1,205,000** | |

Table 4. RRT Operating Related Integration Costs Change

| | |
|---|---|
| $375,000 | Original – Schedule 6.3 |
| **LESS** | |
| $81,000 | Change to August, 2003 costs[35] |
| $107,000 | Regulatory included in Hearing costs |
| **PLUS** | |
| $88,000 | Additional Regulatory staff costs |
| **$275,000** | |

AUMA/CE recommended that the $630,000 of Regulatory costs from the DRT and $107,000 of Regulatory costs from the RRT be included in hearing costs, subject to Board review and approval.

AUMA/CE noted that the allocation of integration costs between the DRT and RRT functions was done on the basis of number of customers (5/1) while the allocation of delay costs appeared to be done on 50/50 basis. Without meaningful evidence, AUMA/CE recommended a 70/30 allocation of gas/electric FTEs. AUMA/CE argued that this recognized that many of the job requirements were similar for each function and because of the differences in number of customers there was likely more work on the gas side. AUMA/CE submitted that DERS did not provide any supportable, independent review to substantiate the allocations.

**Calgary**

Calgary noted the argument that the legislative and market structure justified the need for DEML to create DERS and to incur start-up costs in order to run a regulated gas services business. Calgary argued that the legislation only required ATCO to unbundle its distribution function. The sale of the retail business and creation of DERS were business decisions carried out between parties who saw investment and/or profit advantages.

Calgary noted that the legislation mentions reasonable and prudent costs of separation. Further, the legislation did not contemplate or envision that separation costs meant integration costs or start-up costs for entering into the business of non-regulated retail services in Alberta. In addition, the "Other costs" in the context of the *DGS Regulation* mean all other costs in the bill, it does not mean a reservoir for whatever costs a particular party may incur by being in the business of selling retail gas services.

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[34] Exhibit 005—40

[35] Exhibit 005—40

Calgary noted that DERS freely acknowledged that these costs were in the nature of setup and start-up activities and argued that these costs should be viewed for what they are; transaction costs and should be treated accordingly, by a full disallowance.

Calgary noted that DERS also characterized the integration costs as transition costs. DERS also acknowledged that there was no definition or even reference to integration costs in the regulation. Calgary argued that the Board had no legislative guidance to allow integration costs or transition costs and there was no precedent or reference point that demonstrates that the inclusion of integration costs serve the public interest.

Calgary noted that the integration costs included $2.7 million for licensing, which included the right to use ATCO I-Tek's Customer Care and Billing systems and an upgrade of the software licenses to permit ATCO I-Tek to process third-party invoices. Calgary argued that these charges were not justified given that DERS chose not to provide details of the licenses. As a result, these costs should be disallowed.

With respect to section 5 of the *DG S Regulation*, Calgary considered that the provision of gas services could be achieved within ATCO. Furthermore, Calgary argued that the major costs associated with that separation were included with ATCO Gas's 2003/2004 GRA which was approved in Decision 2003-072.[36]

Calgary argued that there were no provisions in the legislation that would allow recovery of the integration costs prior to the date of commencement of the operation of default gas supply and submitted that costs of separation of were not costs of integration. Furthermore, Calgary stated that DERS was not a DSP until the Board approved DERS as a DSP. Calgary indicated that DERS was not an owner under the electric regulations until such time as the Board approved the application. As such, business costs incurred were similar to costs of entering the market place, which should be borne by the shareholders and not by the consumers.

Calgary noted that DEML equated integration costs with stranded costs. Calgary argued that stranded costs were costs that were previously approved and by virtue of a change in the rules, were no longer recoverable from ratepayers in the normal course of business. With respect to DERS, there were simply no costs that were previously approved or included in rates. Calgary submitted that the Board should give no weight to DERS's testimony suggesting that disallowed integration costs would be stranded costs.

Calgary noted that DERS championed certain OEB guidelines in support of including proposed integration costs in tariffs. Calgary pointed out that the legislation from Ontario bears little similarity to that in Alberta and submitted that Ontario has no default gas supplier proposition, nor does it have the separation requirements as enumerated in the *DGS Regulation*.

Calgary submitted that DEML's use of the OEB Electricity Distribution Rate Handbook to support its argument was not helpful, given that the handbook deals with electricity distribution companies under Performance Based Rate-Making (PBR), a regime with a uniform system of accounts and was for distribution companies. Calgary submitted that reliance on Ontario documents should be disregarded and given no weight.

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[36] Decision 2003-072 – ATCO Gas, 2003/2004 General Rate Application, dated October 1, 2003

Calgary noted that based on DERS's filing dates and proposed test years, DERS considered that 10 weeks would be required to fully deal with the Application. Calgary noted the significant time required for the transfer of assets from TransAlta Utilities Corporation (TransAlta) to AltaLink and argued that DERS should have known that 10 weeks was not a reasonable time frame.

Calgary argued that based on the timelines in the Application, DERS would have needed to file its Application in December 2002 or January 2003 for an August start date. Calgary also pointed out that from the start, the ability to close this transaction was highly dependent upon the regulatory environment and the timeliness of extensive legislative and regulatory activities and approvals.

Calgary argued that DEML decided to proceed down a course that it knew would not be manageable, yet it continued to incur costs. The period of delay and the costs during the delay were in the hands and in the total discretion of DERS. The so-called delay was not caused in any way by the regulatory process. Calgary suggested delay costs were a misnomer, because the costs were incurred voluntarily by DERS. Calgary submitted that these so-called delay costs should not be included in the revenue requirement or in the integration costs.

Calgary noted that DERS suggested that integration costs of a similar nature would be incurred by any entity that complies with the requirements of the legislation and implemented a completely separate regulated retail service provider. However, in its ATCO Retail Sale argument, Calgary noted that Mr. Beckett stated that such costs were not necessary to comply with the separation contemplated by the legislation.

Calgary noted that DERS indicated that it would allocate deferred or capitalized items between regulated and unregulated entities based on number of customers. Calgary submitted that this was inappropriate, as it would not provide appropriate matching of costs and benefits. If deferred or capitalized costs were allocated at the outset based on the number of customers, and the number of customers changed over time, then there would be a disproportionate share of capital costs allocated over time.

Calgary argued that DERS should first determine the amortization amount, then based on the number of customers in each of regulated and unregulated entities, the cost should be allocated to DERS and DEP. This process would provide a more accurate matching of costs and benefits. Such a process also obviates the need to estimate switch rates over the amortization period, which was discussed during the hearing.

### CCA

The CCA noted that DERS proposed to allocate integration costs on the basis of customers, as costs in this category were directly related to the number of customers. The CCA considered that the allocation of integration costs should be based on an assignment of 50% of the costs to customers and 50% to energy. The CCA considered that it was inappropriate to allocate integration costs simply on the basis of customer numbers.

## Consumer Group

The Consumer Group noted that DERS considered that its integration costs met the criteria established by the OEB in approving integration costs and noted that DERS relied on OEB Article 480.

The Consumer Group noted that the OEB excluded costs related to wire company separation and reorganization from consumer rates in this policy.

Based on a decision from the OEB, the Consumer Group considered that transition or integration costs should be separated into corporate reorganization and re-engineering costs and that corporate organization and reorganization costs should be assigned to the shareholder.

The Consumers Group argued that DERS's integration costs were the same costs referred to by OEB as transition costs, which were specifically disallowed. In general, the Consumer Group argued that start-up costs and delay costs should not be eligible costs for inclusion into the revenue requirement.

The Consumer Group submitted that customers should not be held responsible for business start-up costs and delay cost and argued that delay costs would result in customers paying costs for the same service to ATCO and DERS with no added benefit. The Consumer Group argued that it was only reasonable for customers to be asked to pay for costs for which they receive a benefit and in the absence of a commensurate and tangible benefit, the Board should exclude such costs from regulated rates.

The Consumer Group considered that prudent costs reflected efficient operations and was concerned that DERS was motivated to minimize the costs of its non regulated functions rather than minimizing the costs of DERS.

The Consumer Group argued that since DERS appeared to consider that the Code of Conduct would not apply until the Retail Sale Application was approved, it followed that section 5 of each of the *RDS Regulation* and *DGS Regulation* would have to be interpreted to mean that "integration costs", incurred prior to the moment DERS was approved by the Board as an owner or as DSP, should not be recovered.

The Consumer Group argued that the risk of legislation being approved and the timing of that approval was one DEML should bear, not customers. Customers should not be held responsible for the business decisions of DEML.

The Consumer Group considered that DEML was anxious to enact its business plan which resulted in significant delay costs. The Consumer Group argued that these delay costs were imprudent and should be disallowed from regulated rates. The Consumer Group stated that there was no justification for charging customers the delay costs associated with DEML's desire to begin operations once the legislation was enacted and the regulatory requirements had been met.

Should the Board approve any delay costs, the Consumer Group submitted that they should be treated as long-term assets and allocated between regulated and non-regulated operations.

The Consumer Group noted that operating integration costs would be fully deductible for tax purposes by DEML and that capital integration costs would be treated like other capital expenditures for tax purposes with DEML claiming the relative amounts of Capital Cost Allowance. The Consumer Group also noted that DERS indicated that there was a time value of money benefit to DEML of $112,344 associated with the operating costs and $113,674 associated with the capital costs as a result of these tax deductions.

The Consumer Group submitted that any benefit to DEML from the tax deductibility of expenditures within the regulated business would act as a subsidy to the unregulated side of DEML. Accordingly, the timing difference benefit to DEML should flow to the regulated side. One possible way of reflecting this benefit would be to reduce any eligible integration costs by the amount of the benefit.

The Consumer Group considered that the reduction in taxes to DEML was a more significant benefit than the timing differences, as every dollar of expenditure deducted, would result in a tax saving. The timing when this tax saving would be realized was dependent on the difference between the rate of amortization of the expenditure for income statement purposes and the tax depreciation rate or Capital Cost Allowance rate. If the Capital Cost Allowance rate were higher than the book amortization, the saving would be realized earlier. The effect of timing differences on taxes paid would mean tax savings in earlier years would be reversed in later years.

The Consumer Group noted that in Exhibit 005-20, DERS captured the timing difference benefit to DEML as a result of the tax deductibility of integration costs incurred by DERS. However, the overall tax saving resulting from the deductibility of integration costs was not reflected. The Consumer Group considered the following example as a demonstration that the tax savings are real and separate from timing differences:

**Table 5. Tax Implications of Integration Costs – Consumer Group**

| Year | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| Tax Rate | 35% | - | - | - |
| CCA Rate | 50% | - | - | - |
| Capital Expenditure | 100 | | | |
| Amortization Deducted in Income Statement | -25 | -25 | -25 | -25 |
| Add Back Book Amortization | 25 | 25 | 25 | 25 |
| Deduct CCA | -50 | -50 | | |
| Impact on Taxable Income | -50 | -50 | 0 | 0 |
| Tax Saving | -17.5 | -17.5 | 0 | 0 |
| Timing Difference | 25 | 25 | -25 | -25 |
| Deferred Tax | 8.75 | 8.75 | -8.75 | -8.75 |

The Consumer Group submitted that according to the example, $100 of capital expenditure amortized over four years for book purposes would generate tax savings of $35 over the life of the capital item. In the initial years, deferred taxes would be increased and in later years, would be drawn down to a zero balance.

The Consumer Group recommended that integration costs should be calculated net of all tax saving realized by DEML, having regard to the timing of receipt of those savings and argued that by not reflecting tax benefits realized by DEML, would benefit the unregulated division of DEML.

The Consumer Group considered that licensing integration costs should not be allocated to the regulated business, as customers have already paid the costs for developing the systems and it would be inappropriate to charge the further amount.

The Consumer Group considered that it would be inappropriate to have DERS customers cover the capital and operating integration costs for operations to support non regulated activities. Nor would it be appropriate for Alberta customers to effectively fund, or help fund, the start-up costs of operations outside of Alberta. The Consumer Group argued that it would also be very damaging to the competitive market to allow DEP to achieve cost advantages in start-up by the inappropriate allocation of costs of deregulated operations from regulated operations.

The Consumer Group expressed concern that the proposed computer system and other infrastructure would generate benefits into the future for non-regulated service in Alberta and service outside of Alberta.

Therefore, the Consumer Group recommended that 50% of the total capital and operating costs be treated as assigned to DEML's unregulated business for the determination of DERS's 2004 rates. The Consumer Group considered the remaining 50% represents the maximum amount that should be allocated to regulated customers and may need to be further reduced in future years.

Finally, the Consumer Group recommended all legal and external regulatory fees be subject to Board review in the same manner as any other hearing cost.

### HVAC

HVAC questioned whether or not it was just and reasonable for customers of a yet to be authorized DSP to become responsible for recovery of costs that were not in any way attributable to that function or service. HVAC argued that the Board's process has not caused the delay in allowing DERS to proceed with its intended course of action and submitted that Competition Bureau approvals were outstanding and data testing had not yet occurred.

### PICA

PICA noted that the CCA submitted that it was inappropriate to classify all integration costs to the customer category. PICA submitted that any integration costs allowed by the Board, if any, primarily track the number of customers assumed by DERS. Further, DERS's allocation of integration costs between regulated and unregulated reflected a split based on number of customers. Therefore, it would be inconsistent to classify any portion of indirect costs as energy related.

### Views of DERS

DERS considered that the separation of the regulated retail function from the distribution function mandated by the new legislation framework had resulted in certain costs required to perform the RRT and DRT functions. These "integration costs" were one time in nature and would be required by any provider that implemented a separate regulated retail service.

DERS considered that the integration costs represented prudently incurred costs that fit within the cost recovery principles of section 5 of both the *RDS Regulation* and the *DGS Regulation*.

DERS also noted subsection 3(1) of the *DGS Regulation* and commented that a parallel provision was contained in subsection 103(1) of the EUA governing the provision of electricity services to eligible customers. DERS considered that prudent costs and expenses incurred in respect of providing regulated retail services must be included in the tariffs and the time at which the costs were incurred does not bear upon the issue of whether costs were prudently incurred in order to provide regulated retail energy services.

In support of its integration costs, DERS referred to the detailed policy of the OEB concerning the recovery of transition costs that were incurred by electric distribution utilities as a result of electricity market restructuring in Ontario.

DERS noted that the policies and decisions of the OEB do not bind the Board, however, DERS considered that the OEB's criteria provided a fair and rational foundation for the recovery of costs that fit the description of transition or integration costs.

DERS noted that as a result of the delay of the implementation date from August 1 to December 1, 2003, delay costs would be incurred. DERS submitted that these costs related to salaries, employee-related costs, information system costs as they relate to maintenance and some corporate costs. DERS stated that these costs were a result of hiring people, acquiring infrastructure and software and renting facilities during the period or prior to August 1. DERS argued that these costs were fixed.

DERS submitted that without knowing when the new legislative framework would be enacted, it would have been impossible to estimate when the RRT and DRT Applications could be filed with the Board. DERS stated that in the course of developing the Application, it was necessary for DERS to make an assumption as to a possible implementation date and then ensure that all measures were taken to enable DERS to be in a position to commence the regulated retail function, assuming all conditions precedent were satisfied and the transaction would close. DERS submitted that the delay costs should be approved for inclusion in the revenue requirement as part of the integration costs.

DERS noted that Calgary argued that the OEB guidelines were not applicable because the guidelines were applied in respect of a PBR process and in respect of electric distribution utilities. DERS stated that it presented the OEB policy in support of the recovery of integration costs and did not state that the OEB policy could or should be applied word for word.

DERS argued that section 5(a) of the *RDS Regulation* and the *DGS Regulation* do not limit the Board's ability to approve integration costs. If DERS was approved as the regulated retail service provider, it doesn't matter that the costs were incurred prior to DERS acquiring that status so long as the costs are prudent. Accordingly, DERS disagreed with AUMA/CE' assertion that the Board does not have the jurisdiction to award any integration costs or delay costs prior to DERS commencing operations.

DERS noted the Consumer Group considered that the level of costs charged to regulated customers was excessive and reflected a subsidy of unregulated activities. DERS argued that there was no evidence to support this view, and that it had retained Cap Gemini to ensure that the allocations were performed to ensure that the unregulated activities were not subsidized.

DERS also noted the Consumer Group considered that it was not appropriate for customers to pay for corporate start-up or delay costs. DERS stated that corporate organization costs included in delay costs, referred to activities that are centralized at DEML's head office in Toronto. During the delay period, DERS would utilize corporate activities such as payroll, financial reporting, human resources, and executives to support DERS in its rate application and ongoing operations.

DERS noted the Consumer Group suggested that any allowed integration costs should be determined net of all tax savings realized by DEML. DERS argued that the Consumer Group's tax saving calculation was incorrect and the only potential benefit that DEML will have was the time value of money that DERS calculated and included as a deduction.[37]

DERS argued that the Consumer Group table was not correct with respect to the half year rule or that Capital Cost Allowance is calculated on a declining balance basis and in calculating the impact on taxable income. DERS considered that the correct portrayal of the tax saving/liability was shown in Table 6:

**Table 6. Tax Implications of Integration Costs – DERS**

| Year | 1 | 2 | 3 | 4 |
|---|---|---|---|---|
| Tax Rate | 35% | - | - | - |
| CCA Rate | 50% | - | - | - |
| Capital Expenditure | 100 | | | |
| Revenue | 25 | 25 | 25 | 25 |
| Amortization Deducted in IS | -25 | -25 | -25 | -25 |
| Accounting Income | 0 | 0 | 0 | 0 |
| Add Back Book Amortization | 25 | 25 | 25 | 25 |
| Deduct CCA | -50 | -50 | | |
| Taxable Income (Loss) | -25 | -25 | 25 | 25 |
| Deferred Tax Liability (Saving) | -8.75 | -8.75 | 8.75 | 8.75 |

DERS noted that it had calculated the time value of money benefit under the liability method of accounting for income taxes to the regulated customers, and stated in its revised schedules that the time value of money benefit should be subject to deferral account treatment as the benefit only accrues to the extent that DEML was taxable.

DERS noted the Consumer Group suggested that it was inappropriate to charge customers integration costs related to I-Tek service initiation and licensing, as customers have already paid to develop the CIS system. DERS argued that the record indicated that this cost related to the licensing of the full suite of software required to provide customer care, as well as considerable infrastructure required by I-Tek and was not related to software development.

### Views of the Board

The Board has reviewed the submissions from interveners and DERS regarding the integration and delay costs proposed by DERS. The Board notes that generally interveners opposed or suggested reductions to the integration and delay costs, while DERS considered that the costs were reasonable and prudently incurred in bringing forth this Application.

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[37] The time value benefit was included in the revised Schedule 6.4 to the DRT Application and the revised Schedule 6.3 of the RRT Application. Exhibit 005-40.

The Board will consider these costs in two categories, namely capital integration costs and operating integration costs (including delay costs).

With respect to the capital integration costs, the Board notes that the majority of these costs are related to information systems and I-Tek implementation. The Board considers that these costs are necessary to allow the separation of electricity and gas distribution services from the provision of electricity and gas services, and that these systems are necessary for the provision of ongoing DRT and RRT service to regulated customers.

The Board notes that Calgary proposed that the $2.7 million in capital integration costs associated with licensing should be disallowed on the basis that DERS did not provide details of the licenses. The Board also notes the argument of DERS that without the licensing, costs would have been four to five times greater than what was paid to ATCO I-Tek in order to obtain the same CIS functionality. Considering all of the above, the Board concludes that the costs associated with licensing are reasonable.

Therefore, the Board will approve DERS's capital integration costs of $6,003,000 for the DRT function and $3,239,000 for the RRT function.

With respect to the operating integration costs, the Board notes that the operating integration costs totaled $4,335,000 up to November 30, 2003. The Board considers that based on the release date of this Decision, DERS could begin operations by January 1, 2004. Assuming a January 1, 2004 start of operations, total operating integration costs would be $4,929,000.

The Board notes that DERS indicated[38] that in TransAlta's sale of transmission assets to AltaLink, TransAlta's sale of distribution business to Aquila, and the sale of the RROT function from Aquila to EPCOR, operating integration and delay costs were not recovered from customers.

The Board considers that the operating integration costs should be considered as a cost of market entry and that these costs should therefore be borne by shareholders. Accordingly, the Board denies DERS's request to recover any operating integration costs (including delay costs) from customers.

The Board also notes that the Separation Cost Provisions refer to the separation costs of an "owner" under section 5(1)(b) of the *RDS Regulation* and of a "default supply provider" under section 5(b) of the *DGS Regulation*. As DERS would not be considered either as an "owner" or a "default supply provider" until the retail sale transaction with ATCO closes, the Board finds that the Separation Cost Provisions are of no assistance to enable the recovery of either operating integration or delay costs.

## 3 ELECTRICITY REGULATED RATE TARIFF (RRT)

With respect to its RRT, DERS proposed three tariff components. The first component, which is discussed further in section 3.2, is a Pool Price Flow-Through Rate (PPFR) that would be used to recover the cost of electricity and energy related revenue requirements. The other two components are a Customer Charge and Variable Charge and these two charges would be used to recover the non-energy revenue requirements associated with the RRT. The non-energy revenue requirements and associated rate design are discussed in section 3.1.

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[38] Response to Undertaking Given by Mr. Hemstock to Mr. McNulty Tr. p. 944

## 3.1 Customer Charge, Variable Charge and Non-Energy Revenue Requirements

### 3.1.1 Non-Energy Revenue Requirements

DERS's forecast of non-energy revenue requirements, by component, is shown in Table 7. Relative to the forecasts included in the Application, the forecast revenue requirements shown in Table 7 were updated by Exhibit 005-40.[39]

Additional details of the non-energy revenue requirement items are contained in the sections that follow.

Table 7. RRT Non-Energy Revenue Requirements

| | Categories | ($000s)<br>5 month | ($000s)<br>12 month |
|---|---|---|---|
| 1 | Customer Care Costs | $4,034 | $9,533 |
| 2 | **Amortization of Integration Costs - Capital** | $272 | $648 |
| 3 | **Amortization of Integration Costs - Operating** | $253 | $603 |
| 4 | Working Capital | $298 | $603 |
| 5 | Credit Charges | $12 | $29 |
| 6 | Amortization of Hearing Costs | $148 | $352 |
| 7 | **Other Operating Costs** | | |
| | **7.1 Staff Salaries** | $468 | $1,166 |
| | **7.2 Customer Education & Energy Awareness** | $227 | $546 |
| | **7.3 Information Systems** | $67 | $160 |
| | **7.4 Other Administration Costs** | $36 | $75 |
| | **7.5 Interest on Security Deposits** | $17 | $40 |
| | **7.6 Corporate Costs** | $247 | $508 |
| 8 | Bad Debt | $383 | $857 |
| 9 | Penalty Revenue | -$422 | -$942 |
| | Total Non-Energy Revenue Requirement | $6,040 | $14,179 |

Note: DERS proposed that the **bolded** categories in this table do not go into a deferral account

#### 3.1.1.1 Customer Care Costs

DERS's forecast revenue requirements for RRT customer care costs are shown in Table 8. The Board will address customer care costs for the RRT in section 4.1.1.1.

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[39] RRT Schedule 6.1 from Exhibit 005-40

Table 8. RRT Customer Care Costs

| Customer Care Costs | 5 month | 12 month |
|---|---|---|
| Billing Services | 2,093 | 4,996 |
| Customer Assistance Services | 918 | 2,061 |
| Walk-in Services | 92 | 222 |
| Credit Management Services | 316 | 764 |
| Other Additional Services | 52 | 126 |
| Time & Materials | 16 | 38 |
| Postage and Stationery | 528 | 1,277 |
| Incremental Processing | 19 | 47 |
| Total | 4,034 | 9,533 |

#### 3.1.1.2 Amortization of Integration Costs

The Board will address amortization of integration costs for the RRT in section 4.1.1.2.

#### 3.1.1.3 Working Capital Costs

The Board will address non-energy working capital costs for the RRT in section 4.1.1.3.

#### 3.1.1.4 Credit Charges

The Board will address non-energy credit charges for the RRT in section 4.1.1.4.

#### 3.1.1.5 Amortization of Hearing Costs

The Board will address hearing cost expense for the RRT in section 4.1.1.5.

#### 3.1.1.6 Other Operating Costs

The Board will address other operating costs for the RRT in section 4.1.1.6.

#### 3.1.1.7 Bad Debt Expense

The Board will address bad debt expense for the RRT in section 4.1.1.7.

#### 3.1.1.8 Penalty Revenue

The Board will address penalty revenue for the RRT in section 4.1.1.8.

### 3.1.2 Non-Energy Revenue Requirement Allocation and Rate Design

The Board will address the allocation of the RRT non-energy revenue requirement to rate classes and RRT rate design in section 4.1.2.

## 3.2 Pool Price Flow-Through and Energy Revenue Requirements

### 3.2.1 Energy Procurement and Price Setting Model

DERS indicated that it would follow the current ATCO Electric methodology for the determination of a pool price flow-through charge.

### Views of the Interveners

### Consumer Group

The Consumer Group recommended that the Board direct DERS to maintain sufficient records to ensure the details of the pricing methods employed were available for review by the Board and interveners if questions arise regarding the calculation and allocation of the energy purchases.[40]

The Consumer Group submitted that in order to educate customers about the electricity marketplace and future pricing trends, DERS should be directed to communicate forward price information to all RRT customers similar to the direction provided to ATCO Electric in Decision 2002-106.[41] The Consumer Group submitted that the forward price information provided should reflect each customer group's (i.e. residential, farm, commercial) load shape, including the forward price for peak product and super peak in appropriate proportion, along with the forward base price. The Consumer Group also stated that the forward price should also include a factor for losses and the Pool trading charge.

### Views of DERS

DERS submitted that a flow-through energy charge was the most appropriate basis for pricing energy to RRT customers since section 2(1)b and (c) of the *RDS Regulation* mandates the use of a flow-through pricing mechanism for electricity for other than residential, farm, and irrigation customers as of January 1, 2004, and for all customers as of January 1, 2006.

DERS argued that it would be inappropriate and disruptive to customers to deviate from the flow-through methodology for residential, farm, and irrigation customers in this Application.

### Views of the Board

As noted in section 2.1.2, the *RDS Regulation* was amended and the Board considers it reasonable to grant an extension to DERS with respect to the date of implementation of a transition rate. Therefore, the Board will accept the use of a flow-through rate as proposed by DERS in the Application until July 1, 2004.

The Board agrees with the Consumer Group's recommendation that DERS should maintain sufficient records to ensure the details of the pricing methods employed are available for review by the Board if questions arise regarding the calculation and allocation of the energy purchases.

The Board notes the Consumer Group's request that DERS should provide forward price information for customers. The Board considers that some forward price information may be useful for customers, but that the requirement for this information may be lessened as a result of the amendments to the *RDS Regulation*. If still required, the Board considers that it would be more appropriate for a province-wide entity to provide this information, such as the Department of Energy through its Customer Choice website, since all electricity customers in the province might benefit from this information.

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[40] CCA.DERS-15(a)]

[41] Decision 2002-106 – ATCO Electric Ltd., 2003 Regulated Rate Option Tariff, Part A: 2003 Energy Rates, dated December 11, 2002

### 3.2.2 Energy Revenue Requirements

DERS indicated that its pool price flow-through charge will consist of the cost of purchased electricity and Power Pool trading fees.

#### Views of the Interveners

#### Consumer Group

The Consumer Group submitted that the actual rate for trading fees should be included in the energy cost charged to customers. The Consumer Group also indicated that DERS should state the loss factor included in the energy rate and upon reconciliation of the deferral account, specify the actual loss factor. The Consumer Group also submitted that variances between the forecast and actual unaccounted for energy (UFE) should be investigated and details explained in the true up of the deferral account.

#### Views of DERS

DERS indicated that the allocation of certain costs between the energy and non-energy revenue requirements, as is done in the DRT, would be addressed by DERS in future applications. DERS submitted that the Application maintains all but purchased energy and Power Pool trading fees in the non-energy revenue requirement in the interest of providing as seamless a transition as possible from ATCO Electric to DERS.

#### Views of the Board

The Board agrees with the Consumer Group that the actual fee for pool trading charges should be included in the energy cost charged to customers. The Board understands that this will be the effect of DERS's proposed energy deferral account.

The Board does not agree with the Consumer Group that DERS should state the loss factor included in the energy rate or that DERS should be required to explain differences between forecast and actual UFE. The Board does not consider that it is reasonable for DERS to differentiate between losses and UFE, and the Board does not consider that DERS is in a position to explain differences between forecast and actual losses/UFE.

The Board will address the allocation of certain costs to energy and non-energy revenue requirements of the RRT in section 3.3.2.

### 3.2.3 Pool Price Flow-Through Rate (Rider P)

DERS noted that the methodology for the calculation of this charge was specified in the Application [42] and submitted that the method for calculation was identical to that currently employed by ATCO Electric. DERS requested approval of the flow-through rate calculation as provided on the Rider "P" Schedule.

The Board considers DERS's proposed method of calculating the PPFR to be reasonable. The Board notes that no intervener commented on DERS's proposed method of calculating the PPFR. The Rider "P" Schedule approved by the Board is included in Appendix 8 of this Decision.

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[42] Rider "P" Schedule in Attachment 3 to Exhibit 002-001 of the RRT Application

## 3.3 Other Matters

### 3.3.1 Customer Forecast, Load Forecast and Energy Purchases

DERS forecast total number of RRT customer months and corresponding consumption (sales or load) for five-month and twelve-month test periods for the rate classes are shown in Table 9. The period from August to December 2003 was used as the basis for the five-month test period and calendar 2004 was used as the basis for the twelve-month test period.

For the five-month test period, DERS indicated that it used ATCO Electric's methodology outlined in its 2003 RROT Non-Energy Cost Application to forecast the number of RRT customers and RRT sales.

For 2004, DERS noted that its forecasts of customer and load retention rates by rate class were based on both ATCO Electric's historical data and DERS's expectation of the market.

To calculate the total number of RRT customers and sales, DERS indicated that it used a two-step approach.

- Calculation of the load eligibility factor or the total RRT eligible customers within each rate class as a percentage of total customers in the same rate class.
- Calculation of the load retention factor or how many RRT eligible customers in each rate class would choose the RRT.

DERS submitted that according to the *RDS Regulation*, all residential, farm, irrigation and other customers with consumption less than 250 MWh per year were eligible for the RRT and therefore, the RRT eligibility factor for these customers was 100 percent. DERS also noted that the Small General Service, Large General Service, and Oilfield Service rate classes have an eligibility factor of less than 100 percent.

DERS noted that Small General Service RRT customers were estimated to switch more aggressively to non-regulated retail services and by the end of 2003, less than 30% of eligible Large General Service customers were expected to remain on the RRT due to self-retailing opportunities and alternative non-regulated supply offerings.

DERS noted that the amount of energy purchased for RRT customers was a combination of both energy consumption and distribution energy losses. DERS indicated that it adopted ATCO Electric's energy loss determination it used in its 2001 and 2002 RROT Non-Energy Cost Applications and the percentage energy loss was assumed to be unchanged from 2003 to 2004.

The results of DERS's forecasts are shown in Table 9 and these results were used to allocate non-energy revenue requirements to the various rate classes.[43]

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[43] RRT electricity purchase forecasts are included in Schedule 4.1 and 4.2 in the Application.

## Table 9. RRT Cost Allocators by Rate Class

**5 Month Test Period**

| Rate Classes | | No. of RRT Customers Months | % | No. of RRT Bills after Consolidated Billing (#/year) | % | RRT Sales (kW.h/year) | % |
|---|---|---|---|---|---|---|---|
| Residential | E1 | 569,721 | 71.48 | 558,327 | 72.22 | 318,543,406 | 49.69 |
| Small General | E2 | 85,655 | 10.75 | 85,655 | 11.08 | 172,405,115 | 26.89 |
| Large General | E3 | 2,184 | 0.27 | 1,398 | 0.18 | 34,564,159 | 5.39 |
| Oilfield | E4 | 2,540 | 0.32 | 2,540 | 0.33 | 8,412,320 | 1.31 |
| Farm | E5 | 81,951 | 10.28 | 81,951 | 10.60 | 102,695,684 | 16.02 |
| Lighting | E6 | 54,785 | 6.87 | 43,007 | 5.56 | 3,008,680 | 0.47 |
| Irrigation | E7 | 205 | 0.03 | 205 | 0.03 | 1,420,124 | 0.22 |
| **TOTAL** | | **797,042** | **100.00%** | **773,083** | **100.00%** | **641,049,488** | **100.00%** |

**12 Month Test Period**

| Rate Classes | | No. of RRT Customers Months | % | No. of RRT Bills after Consolidated Billing (#/year) | % | RRT Sales (kW.h/year) | % |
|---|---|---|---|---|---|---|---|
| Residential | E1 | 1,387,302 | 72.27 | 1,359,556 | 72.99 | 813,194,314 | 51.86 |
| Small General | E2 | 202,854 | 10.57 | 202,854 | 10.89 | 414,696,167 | 26.45 |
| Large General | E3 | 3,599 | 0.19 | 2,303 | 0.12 | 56,343,872 | 3.59 |
| Oilfield | E4 | 2,500 | 0.13 | 2,500 | 0.13 | 8,402,562 | 0.54 |
| Farm | E5 | 193,525 | 10.08 | 193,525 | 10.39 | 264,987,776 | 16.90 |
| Lighting | E6 | 129,386 | 6.74 | 101,568 | 5.45 | 7,086,701 | 0.45 |
| Irrigation | E7 | 478 | 0.02 | 478 | 0.03 | 3,369,706 | 0.21 |
| **TOTAL** | | **1,919,645** | **100.00%** | **1,862,785** | **100.00%** | **1,568,081,098** | **100.00%** |

### Views of the Interveners

No parties provided comments.

### Views of DERS

DERS submitted that its customer, load and energy purchase forecasts were required for determination of energy and non-energy revenue requirements, allocation of costs to the various rate classes and calculation and disposition of deferral accounts.

DERS submitted that the differences between forecast and actual customers and load will impact revenues and costs and will be reconciled through in the revenue deferral account and certain cost deferral accounts. DERS also submitted that differences in forecast and actual energy purchases will be reconciled through the energy deferral account.

DERS requested approval of its customer, load and energy purchase forecasts for the proposed test periods.

### Views of the Board

The Board notes that DERS established customer and load forecasts for the same rate classes used by ATCO Electric in its 2003 Non-Energy RROT Application.

The Board notes that the differences between forecast and actual customers and sales will impact revenues and costs. However, the Board also recognizes that the forecast and actual non-energy revenues and costs will be reconciled in the non-energy revenue deferral account and certain cost deferral accounts. The Board also notes that differences between forecast and actual electricity purchases will be reconciled through the Deferred Electricity Account (DEA).

With respect to the calculation and disposition of deferral accounts, the Board notes that DERS indicated that it would use actual customer numbers, actual sales and actual revenue by rate class in the reconciliation process.[44] The Board also notes that forecast distribution energy losses will be adjusted to actual energy losses through the deferral account process.[45]

Recognizing that virtually all revenues and costs that vary with customers or sales will be subject to deferral account treatment, the Board does not consider that any adjustment to the forecasts prepared by DERS is necessary for the purposes of this Decision.

### 3.3.2 Deferral Accounts

DERS proposed that energy and non-energy cost deferral accounts be used for its RRT. Table 10 below shows the proposed deferral accounts and the cost categories for which DERS requested final approval of its cost forecast (non-deferral). Table 7 shows the forecast revenue requirements associated with deferral and non-deferral, non-energy revenue requirement items.

DERS noted that its opening balance for each deferral account will equal the closing balance of each corresponding ATCO Electric deferral account as outlined in the EATA.[46] In the Retail Sale proceeding, ATCO Electric noted that although the balances will be transferred, ATCO Electric would be responsible for all reconciliation with respect to those balances.[47] DERS noted that ATCO Electric would be responsible for the RRT reconciliation for the period up to the transfer date and DERS would be responsible for the RRT reconciliation following the transfer date.[48] DERS also noted that ATCO Electric would remain the party responsible for any prior period adjustments to its energy deferral account made subsequent to the Adjustment Time described in the EATA. DERS noted that as any such adjustments were made and approved by the Board, they will be transferred to DERS energy deferral account which will be disposed of on an annual basis.[49]

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[44] AUMA/CE-DERS (DRT)-13

[45] PICA-DERS (RRT)-2

[46] The Electricity Assets Transfer Agreement was filed as part of the Retail Sale Application.

[47] BR-ATCORT-6

[48] CCA-DE-1

[49] BR-DERS-8

Table 10. RRT Deferral and Non-Deferral Accounts

| Category | Cost |
|---|---|
| ***Energy Categories*** | |
| Electricity Costs | Deferral |
| Trading Fees | Deferral |
| ***Non-Energy Categories*** | |
| Customer Care Costs | Deferral |
| Amortization of Integration Costs[50] | Non-Deferral |
| Working Capital | Deferral |
| Credit Charges | Deferral |
| Amortization of Hearing Costs | Deferral |
| Other Operating Costs | Non-Deferral |
| Bad Debts | Deferral |
| Penalty Revenue | Deferral |

Source: Exhibit 005-40, RRT, Table 3.1

### Energy Related Deferral Account

As shown in Table 10, DERS proposed to include electricity costs and trading fees in its Deferred Electricity Account (DEA). DERS proposed to recover these costs through a PPFR, that will be revised monthly, and through an annual final reconciliation of the deferral account components.

DERS proposed to use a flow-through rate-pricing model for calculating the PPFR Rate for each customer's billing period. DERS noted that under the flow-through rate methodology, the electricity price for billing purposes would be based on initial hourly consumption data and once final hourly consumption data was available, a variance in hourly consumption by customer class would result.[51] DERS noted that this variance as well as differences between actual meter reads and settlement allocations or revisions to the hourly pool price would cause a variance in the revenues collected from customers and the cost of the electricity. Therefore, on an annual basis, DERS proposed to use the DEA to track the difference between revenues collected from eligible customers and the actual cost of electricity. Once the final balance of the DEA was confirmed in the third quarter of the following year, DERS indicated that it would file an application with the Board for disposition of the balance.

DERS noted that trading fees represent an assessment to Power Pool participants who buy from or sell electric energy to the Power Pool.

### Non-Energy Deferral Accounts

As shown in Table 10, DERS proposed to have six cost categories included in non-energy deferral accounts. DERS proposed to maintain a non-energy revenue deferral account to accrue differences between forecast and actual non-energy revenues and also to accrue differences between some forecast and actual non-energy costs.

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[50] The time value benefit included in Integration costs will be subject to deferral account treatment.

[51] DERS noted that the final hourly consumption data or final load settlement results will be received seven months after the initial load settlement results.

DERS proposed to revise the forecast numbers for the non-energy deferral account items on an annual basis. However, if the deferral accounts accumulate balances exceeding +/- 10% of the forecast revenue requirement, DERS indicated that it would apply for an early disposition of the deferral account balances and an adjustment to rates for an appropriate period of time.[52]

DERS submitted that the 2004 non-energy deferral account balances are anticipated to be final by March 1, 2005 and following that date, DERS proposed to file an application with the Board for approval of the final disposition of the balance in each 2004 deferral account.

### Views of the Interveners

AUMA and the Consumer Group noted that their views included in section 4.3.2 apply equally to this section.

### Views of DERS

DERS submitted that in Decisions 2000-88 and 2002-85 the Board directed ATCO Electric to maintain deferral accounts in respect of certain revenue requirement items. DERS proposed to utilize deferral accounts for those same revenue requirement items. In addition, DERS submitted that the primary difference between deferral accounts of ATCO Electric and DERS was that DERS requested deferral account treatment of customer care costs.[53]

DERS submitted that deferral accounts have been proposed for those cost items that vary with customer behavior or energy prices and argued that deferral accounts were appropriate for the types of costs proposed for deferral treatment, particularly during times of transition. DERS also stated that the deferral accounts were likely appropriate on an ongoing basis given the nature of DERS's cost-based approach to regulated service.

DERS stated that deferral accounts ensure that customers pay no more or no less than the actual costs incurred to provide service. DERS submitted that this was entirely appropriate for costs that vary either with energy pricing or customer behavior, both of which DERS argued were beyond the direct ability of DERS to control or to forecast with required accuracy.

DERS also submitted that deferral accounts do not, however, mitigate management's responsibility to manage the costs in a prudent manner and DERS noted that the management of DERS will remain accountable to the Board for the prudence of all costs incurred in the provision of regulated service.

DERS submitted that it faced significant uncertainty concerning the number of RRT customers that may switch to unregulated retailers during the 2003 and 2004 test periods and that this uncertainty could lead to the under-recovery or over-recovery of DERS's revenue requirement. DERS stated that the uncertainty was due to three principal factors:

- lack of market history under the EUA, 2003 and the *RDS Regulation*;
- the increase in competition arising from the entry of competitors in the retail electricity market; and

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[52] Exhibit 002-02, BR-DERS-7

[53] Schedule BR-DERS-17(b)

- the conversion of AE's RRT from a fixed price to a Power Pool flow-through.

DERS submitted that it would be appropriate for the Board to approve the applied-for deferral accounts and DERS's proposal for disposition of such deferral accounts.

**Views of the Board**

The Board notes that some interveners identified general issues that were applicable to both the proposed RRT and DRT deferral accounts. The Board will address these joint issues in section 4.3.2 of this Decision.

The Board notes that the interveners were generally not opposed to the cost categories that DERS proposed to include in the deferral accounts.

The Board notes that for the DEA, DERS proposed to include the same cost categories that ATCO Electric proposed in its 2003 RRO Tariff, Energy Rate Application. In its application, ATCO Electric proposed to move trading fees from its non-energy tariff to its energy tariff. In Decision 2002-106, the Board approved the PPFR methodology and incorporation of trading fees in ATCO Electric's 2003 energy rate.

With respect to the cost categories proposed to be included in non-energy deferral accounts, the Board notes that DERS submitted that it proposed to use non-energy deferral accounts for the same cost categories previously approved for ATCO Electric for its RRO. However, the Board also notes that DERS proposed to include additional cost categories in non-energy deferral accounts including credit charges and customer care costs. In its 2003 RROT Non-Energy Cost Application, ATCO Electric requested fixed cost deferrals for credit and collections, the credit management system and a few other items. ATCO Electric also noted in its application that it had initiated negotiations with ATCO I-Tek Business Services to replace existing contracts and as such, the forecast Customer Accounting costs should be treated as placeholders. On December 11, 2002, the Board issued Decision 2002-105[54] that included interim 2003 RRO Non-Energy Rates for ATCO Electric.

The Board notes DERS's submission that deferral accounts were proposed for cost categories that vary with customer behaviour and energy prices, and that these variables were beyond the direct ability of DERS to control or to forecast with required accuracy. With respect to forecast accuracy, the Board is less concerned with accuracy when the cost category is included in a deferral account because customers will only incur actual costs. However, the Board also expects reasonable accuracy so that rates derived on the basis of these forecasts are fairly accurate and future rate adjustments are therefore minimized.

Given the uncertainty concerning the number of RRT customers that may switch to unregulated products, and given that DERS has not requested a return or margin for performing the RRP function, the Board approves deferral account treatment for the requested cost categories.

The Board agrees with DERS's submission that deferral accounts do not mitigate management's responsibility to manage the costs in a prudent manner and that the management of DERS will remain accountable to the Board for the prudence of all costs incurred in the provision of regulated service.

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[54] Decision 2002-105 – ATCO Electric Ltd., 2003 Regulated Rate Option Tariff, Part B: Final 2002 and Interim 2003 RRO Non-Energy Rates, dated December 11, 2002

With respect to assignment of the cost categories to energy and/or non-energy deferral accounts, the Board notes DERS's statement that it might be appropriate for the RRT to be structured similar to its proposed DRT, whereby some categories of costs are included in both the non-energy and energy revenue requirements.[55] The Board also notes that no intervener objected to the assignment of the cost categories to the respective energy and non-energy deferral accounts as proposed by DERS. Therefore, the Board approves the assignment of the cost categories to the respective energy and non-energy deferral accounts as proposed by DERS.

However, with respect to future assignment of the cost categories to energy and non-energy deferral accounts, the Board considers that there may be merit in restructuring the RRT deferral accounts. Therefore, the Board directs DERS to submit a study as part of its next non-energy RRT application that describes the implications of restructuring its RRT deferral accounts in a fashion similar to its DRT deferral accounts.

With respect to the DEA and the requested reconciliation and rate adjustment frequency, the Board notes that a PPFR will be revised monthly for each customer group. The Board also notes that DERS proposed to track the difference between revenues collected from customers and the actual cost of electricity in the DEA and that in the third quarter of the following year would file an application with the Board for disposition of the DEA balance. In light of the amended *RDS Regulation* and DERS's requested extension of the date for the implementation of a transition rate, the Board now expects the disposition application in the first quarter of 2005.

With respect to the non-energy deferral accounts and the requested reconciliation and rate adjustment frequency, the Board notes that DERS proposed to revise the forecast numbers for the non-energy deferral account items on an annual basis and if the deferral accounts accumulate balances exceeding +/- 10% of the forecast revenue requirement, DERS indicated that it would apply for an early disposition of the deferral account balances and an adjustment to the non-energy rates for an appropriate period of time.[56] The Board notes DERS's submission that approximately 80% of the total non-energy revenue requirements in the DRT will be self-correcting as customers switch to unregulated suppliers. The Board also notes that AUMA/CE and the Consumer Group did not oppose the proposed method for reconciling and adjusting the non-energy deferral account items. The Board considers that the additional administration and regulatory costs required for monthly rate adjustments would not justify the possible increased accuracy in rates. Therefore, the Board approves DERS's requested reconciliation and rate adjustment frequency and 10% trigger mechanism for non-energy deferral accounts.

The Board also noted that DERS indicated that the 2004 non-energy deferral account balances should be final by March 1, 2005 and that following that date, DERS proposed to file an application with the Board for approval of the final disposition of the accrued balance in each 2004 deferral account. The Board notes that DERS acknowledged during the hearing that they had not yet looked specifically at the reconciliation methodology. The Board directs DERS to submit its reconciliation filing by May 1, 2005 and to include a detailed description of its reconciliation methodology and a proposal for dealing with any balances.

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[55] Tr. p. 1020. In the Application, DERS proposed that credit charges, working capital, bad debt and penalty revenue be included in both the energy and non-energy related revenue requirements.

[56] Exhibit 002-02, BR-DERS-7

# 4 GAS DEFAULT RATE TARIFF (DRT)

With respect to its DRT, DERS proposed three tariff components. The first component, which is discussed further in section 4.2, is a GCFR that would be used to recover the cost of gas and energy related revenue requirements. The other two components are a Customer Charge and Variable Charge and these two charges would be used to recover the non-energy revenue requirements associated with the DRT. The non-energy revenue requirements and associated rate design are discussed in section 4.1.

## 4.1 Customer Charge, Variable Charge and Non-Energy Revenue Requirements

### 4.1.1 Non-Energy Revenue Requirements

DERS's forecast of non-energy revenue requirements, by component, is shown in Table 11. Relative to the forecasts included in the Application, the forecast revenue requirements shown in Table 11 were updated by Exhibit 005-40.[57]

Additional details of the non-energy revenue requirement items are contained in the sections that follow.

In the DRT Application, the costs of credit charges, working capital, bad debt, and penalty revenue are allocated to both the energy and non-energy revenue requirements.

Table 11. DRT Non-Energy Revenue Requirements

| | Categories | ($000s) | |
|---|---|---|---|
| | | 5 month | 12 month |
| 1 | Customer Care Costs | $20,380 | $47,692 |
| 2 | **Amortization of Integration Costs - Capital** | $503 | $1,201 |
| 3 | **Amortization of Integration Costs - Operating** | $1,028 | $2,451 |
| 4 | Working Capital | $2,173 | $3,260 |
| 5 | Credit Charges | $63 | $148 |
| 6 | Amortization of Hearing Costs | $148 | $352 |
| 7 | **Other Operating Costs** | | |
| | **7.1 Staff Salaries** | $914 | $2,280 |
| | **7.2 Customer Education & Energy Awareness** | $1,148 | $2,754 |
| | **7.3 Information Systems** | $31 | $75 |
| | **7.4 Other Administration Costs** | $179 | $379 |
| | **7.5 Interest on Security Deposits** | $122 | $292 |
| | **7.6 Corporate Costs** | $1,247 | $2,560 |
| 8 | Bad Debt | $421 | $981 |
| 9 | Penalty Revenue | -$964 | -$2,249 |
| | Total Non-Energy Revenue Requirement | $27,394 | $62,175 |

Note: DERS proposed that the **bolded** categories in this table do not go into a deferral account.

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[57] DRT Schedule 6.2 from Exhibit 005-40

### 4.1.1.1 Customer Care Costs

DERS's forecast revenue requirements for DRT customer care costs are shown in Table 12.

Table 12. DRT Customer Care Costs

| Customer Care Costs | 5 month | 12 month |
|---|---|---|
| Billing Services | 10,095 | 24,021 |
| Customer Assistance Services | 5,013 | 10,933 |
| Walk-in Services | 465 | 1,121 |
| Credit Management Services | 1,572 | 3,806 |
| Other Additional Services | 202 | 485 |
| Time & Materials | 80 | 194 |
| Postage and Stationery | 2,855 | 6,898 |
| Incremental Processing | 97 | 234 |
| Total | 20,380 | 47,692 |

### Views of the Interveners

### Ab-Com

Ab-Com noted that DERS claimed to be with the range of FMV regarding the pricing of customer care utilizing the services of ATCO I-Tek. Ab-Com suggested there was conflicting evidence concerning the range of FMV, and that there was no evidence that showed that a better deal, in terms of price and/or service quality, was not available from other service providers.

### AUMA/CE

AUMA/CE submitted that they did not focus any significant efforts on this issue, however AUMA/CE stated concerns regarding the level of customer service that DERS was proposing. AUMA/CE referred to concerns submitted in its Retail Sale Argument.[58]

AUMA/CE suggested that service levels were significantly enhanced, at increased costs to customers, done for the ultimate benefit of DEP. AUMA/CE argued that until a customer survey was completed, service levels should continue to at the current ATCO Gas and ATCO Electric levels, unless the shareholder of DERS wanted to pay for the additional costs related to the enhanced service levels.

AUMA/CE did not recommend a specific reduction to the DERS revenue requirement due to the difference service levels proposed by DERS compared to the current ATCO Gas and ATCO Electric MS Agreements. However, AUMA/CE noted that DERS provided a summary of the ATCO I-Tek/DEML rates and terms and conditions of service.[59] AUMA/CE also noted that DERS provided a comparison of the standards and unit costs for services currently being provided by ATCO I-Tek to ATCO Gas and ATCO Electric.[60]

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[58] AUMA/CE Retail Sale Argument, p. 12-13

[59] Schedule per response to BR-DERS.15(c)

[60] Response to BR-DERS-18

AUMA/CE argued the Board should direct DERS in the Compliance Filing to adopt the same standards and level of service being currently provided by ATCO I-Tek to ATCO Gas and ATCO Electric and apply those to the Board determined unit costs for the ATCO I-Tek/DEML MS Agreement.

**Calgary**

Calgary noted that approximately 76% of DERS revenue requirement was for the customer care services provided by ATCO I-Tek.[61] Calgary addressed the evidence Shari Strain[62] and the PA Consulting Group Report[63] based on the overall impact it would have on customers in the MS Agreement section of this Decision.

Calgary noted that DEML entered into the arrangement with ATCO I-Tek to provide certain customer care services for DEML. Calgary argued that the outsourcing arrangement was not typical of the industry. Calgary argued that through a combination of ATCO I-Tek charges to DEML, ATCO and other ATCO charges, the consequence to customers was excessive costs being proposed for inclusion in tariffs whereby customers would pay virtually twice as much as what it should cost to provide those services.

**FMV**

Calgary argued that DERS did not provide credible evidence to support the FMV of the pricing in the MS Agreement.[64] Calgary noted that the Consumer Group and HVAC also argued the pricing in the MS Agreement was not supported by credible and objective evidence. Calgary concluded that "… the proposed ALL-IN costs for customer care would increase approximately 59% from 2003"[65] and recommended that customer care be adjusted by $43.6 million between DERS and ATCO in order to avoid customer harm.[66]

Calgary submitted that with respect to the evidence of Sheri Strand, there was no one to speak to the evidence except for Ms. Milne, who also prepared some comparative information with respect to the costs associated with the ATCO I-Tek MS Agreement and other outsourcing vendors.

Calgary suggested the evidence of PA Consulting Group should be disregarded in its entirety. Calgary submitted that Dr. Chwalowski was neither independent nor objective. Calgary provided a summary of the shortcomings and inconsistencies in Dr. Chwalowski's report and concluded that his evidence was of absolutely no probative value to the Board.

Calgary provided the evidence of Stephens Consulting[67] and Platts Research & Consulting,[68] which examined the requested DERS Customer Care services from ATCO I-Tek. Calgary noted that none of the DERS or Calgary sponsored evidence was a benchmarking study.[69] However, the Shari Strain evidence, the PA Consulting Report, and the Platts Report examined the range of unit prices to other BPO outsourcer prices.

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[61] Exhibit 005-39 Schedule 6.1 DRT; Schedule 6.2 RRT

[62] DERS DRT/RRT Applications, Volume 2, Appendix D

[63] DERS DRT/RRT Applications, Volume 2, Appendix E

[64] Calgary Argument, Article 6, pp. 11 – 14

[65] Calgary Argument, p. 56

[66] Calgary Argument, p. 109, Table 6

[67] Exhibit 005-034, Exhibit 003-03, and Exhibit 003-007

[68] Exhibit 003-08, Exhibit 003-06, and Exhibit 003-09

Mr. Stephens reached the following conclusions:

- ratepayers would incur an additional $50 each year for the cost of customer care from ATCO and DERS if the sale and applied for tariffs were approved;
- total customer care costs increased by nearly 57% from 2002 to 2004;
- the cost increases were not reasonable given that the same information was being processed by the same CIS system;
- current ATCO I-Tek rates (billing costs plus CIS costs – without the transaction) were not at FMV;
- ATCO gas billing costs plus CIS costs were more than 140% of those costs at Enbridge and BC Gas;
- 2004 combined distribution (ATCO) and regulated retail (DERS) billing costs plus CIS costs were projected to be approximately $48 per customer annually for gas and $110 for electric.[70] Those same costs at Enbridge or BC Gas were approximately $30 per customer annually;
- the ATCO I-Tek MS Agreement contained specific cost inflators annually by CPI from 2003 levels;
- other BPO outsourcing agreements contain productivity factors that reduce costs over time; and
- as computer technology advances costs should come down.[71]

Calgary argued that while the Platts report was inconclusive with respect to whether ATCO I-Tek was providing services at FMV, because Platts did not have enough time to obtain comprehensive market data, when pressed for an opinion Ms. Gogel suggested:

> If I had to come to a conclusion based on the limited evidence, the limited data gathered, I would say that they are more outside the market value than they are inside the market value, but I say that – I say that really hesitantly given that I did not have a robust sample of vendors.[72]

Calgary argued that outsourcing was intended to reduce costs, not increase them, as was the case with the ATCO I-Tek MS Agreement. Calgary also suggested that technology should provide productivity. Calgary submitted that if productivity savings were experienced, they were not being passed on to customers. Calgary suggested customer care costs were actually growing at an alarming rate, not showing reductions.

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[69] DERS 2003 – 2004 RRT/DRT Application, Appendix D, Evidence of Shari Strain, page 4, and Appendix E, PA Consulting Report titled "Competitive Price Assessment", and Exhibit 003-08, Platts Final Report, page 3 "a limited and focused competitive price assessment."

[70] Direct Energy confirmed these numbers at Tr. pp. 956-962 (Direct Energy Hearing)

[71] Exhibit 003-05

[72] Tr. p. 1581

Calgary submitted it would be reasonable to expect that a truly arm's length outsourcing arrangement would result in reduced costs. However, in the case of the ATCO I-Tek/DEML arrangement, the essential arm's length element seemed to be absent.

Calgary suggested that in order to place the FMV for customer care in its proper context, it was essential to understand all sources of costs to be recovered from customers. Mr. Stephens outlined the following:

- Call Centre
- Meter Reading
- Billing
- Payment Processing
- Credit and Collections
- Customer Information System (CIS)[73]

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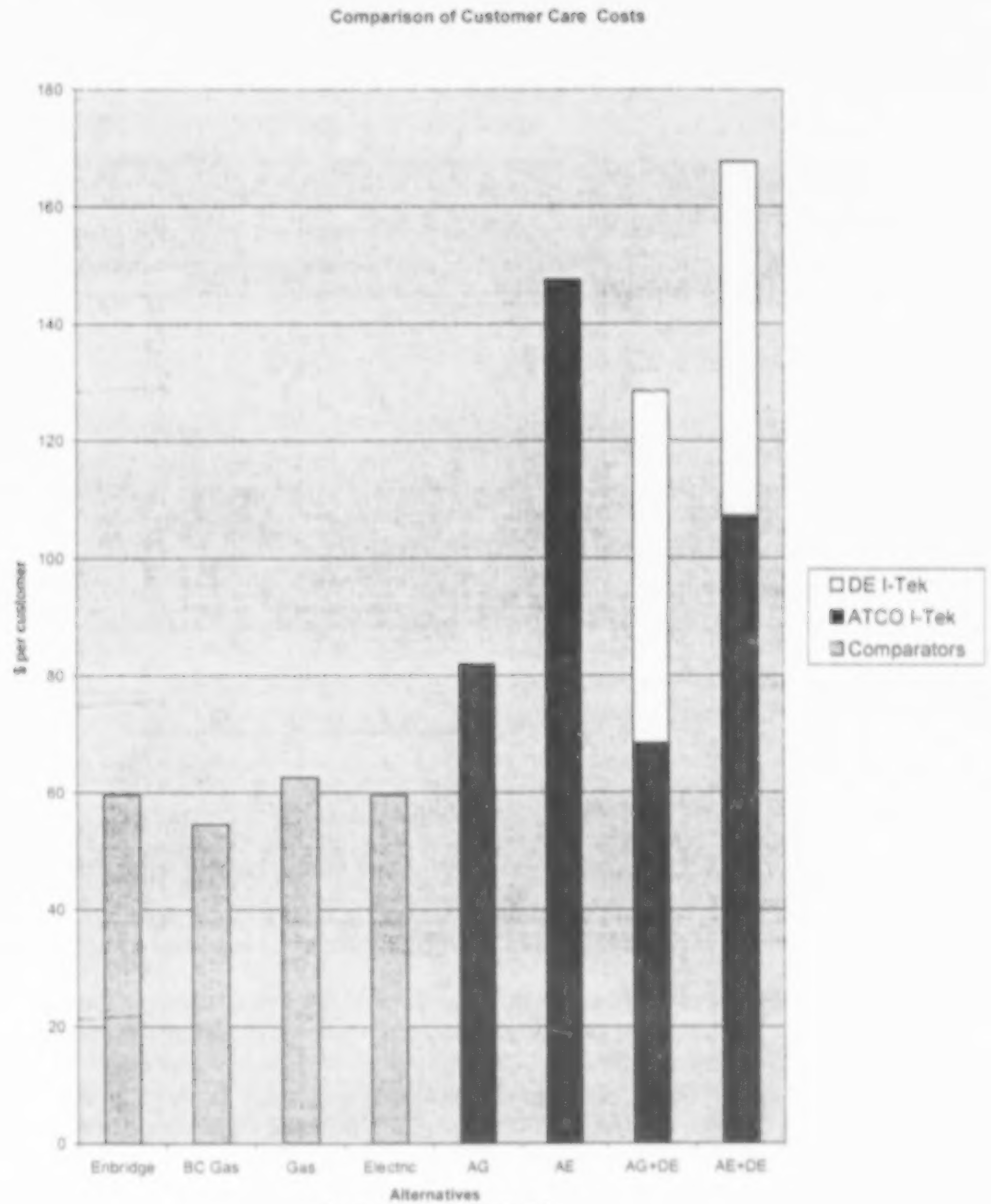
[73] Exhibit 005-34, p. 1, lines 15 to 20

Calgary compared customer care costs for ATCO Gas, ATCO Electric, and DERS to other industry examples.



Source: Stephens Schedule 1.5

Calgary submitted that both customer care costs, and ATCO I-Tek charges were increasing significantly.

Table 13 shows Calgary's ALL-IN customer care costs inclusive of DERS and ATCO.

**Table 13. ALL-IN Customer Care Costs Inclusive of DERS and ATCO**

| | 2004 | 2003 | % Increase |
|---|---|---|---|
| Customer Care Charges through DERS | 59.0 | Nil | |
| Customer Care Charges Through ATCO | 73.0 | 88.4 | |
| TOTAL CUSTOMER CARE CHARGES - ALL IN | 132.0 | 88.4 | 49.3% |

Source: See Tab 2 to Calgary Argument (Stephens Schedules in Exhibit 005-34 and 005-18)

Table 14 shows the ATCO I-Tek charges for 2004 and 2003.

**Table 14. ATCO I-Tek Charges for 2004 and 2003**

| Customer Care Costs - I-Tek Costs ALL-IN | | | |
|---|---|---|---|
| | 2004 | 2003 | % Increase |
| I-Tek Charges through DERS | 57.2 | Nil | |
| I-Tek Charges through ATCO | 40.4 | 55.1 | |
| TOTAL CUSTOMER CARE CHARGES - ALL IN | 97.6 | 55.1 | 77.1% |

Source: See Tab 2 to Calgary Argument
(Stephen Schedules Exhibit 005-034 and Exhibit 005-018)

Calgary submitted that ATCO I-Tek would get paid 77% more to do the same work that it was currently providing for the ATCO utilities. Calgary also submitted that the ALL-IN costs for customer care would increase by approximately 50% from 2003.

Calgary argued that in terms of separation, it was inconceivable that the government would have expected such an increase, both on a percentage and dollar amount basis. Calgary estimated that ratepayers would incur an additional $50 each year for the cost of customer care from ATCO (Gas and Electric) and DERS if the proposed sale transactions and tariffs subsequent to DRT/RRT were approved. Calgary argued that those additional annual costs were not reasonable as there was unlikely to be any payback to the utilities' customers in either the short or long term.

Calgary reiterated that the stand-alone costs asserted by DERS as being necessary, were needless, and therefore imprudent. However, in any event, since DERS persisted in argument to assert that the ATCO I-Tek unit prices were FMV, Calgary repeated its position that the ATCO I-Tek unit prices were not even close to FMV on a stand-alone basis. Calgary argued that the ATCO I-Tek unit prices were not FMV using any of the FMV ranges chosen by the parties to the MS Agreement.

### Interim Rates

Calgary noted that under section 8.5 of the MS Agreement, either party could initiate price review[74] that could be done by way of benchmarking. Calgary suggested that if the Board determined that the ATCO I-Tek charges were directionally too high, it could establish interim rates subject to finalization after the provision of a more complete benchmarking study.

### Base Billing Fee and Minimum Monthly Charge

Calgary noted that the largest of the designated fees for the various services provided by ATCO I-Tek was the monthly base fee, charged by ATCO I-Tek to DERS at a rate of $2.20/service account per month, provided there was a base billing unit volume range of 800,000 to 1.3 million service accounts.[75] Calgary submitted that in return for the $2.20/service account charge, ATCO I-Tek was required to provide 14,000 hours of labour per month, a limited number of complex billing accounts, printing of a single page, double-sided bill per month, including printing of bill messages, folding and inserting into envelopes, reporting processes, and computer processing.[76]

Calgary suggested that the witnesses for DERS demonstrated a lack of understanding of the MS Agreement related to the minimum monthly charge. Calgary submitted that if the number of service accounts[77] dropped below 800,000, the average cost per customer increases since the variable cost becomes fixed.

Calgary determined that DEML/DERS needed only to lose approximately 22% of its customers before a minimum charge would take effect for the Monthly Base Fee. Calgary suggested that if that were to occur ATCO I-Tek would be insulated from DEML/DERS's loss of customers, and the base fee per customer or per unit would increase above the contracted rate of $2.20/service account per month, i.e. the effective cost per customer would increase.

Calgary submitted that the minimum monthly charge condition in section 3.1.2 of the MS Agreement was inconsistent with the representations of DERS in its filing and in its testimony. Moreover, in Calgary's view a minimum monthly charge resulted in a situation where costs were not matched with benefits and customers would end up paying more for no improvement in service. Therefore, Calgary strongly urged the Board to disallow an MS Agreement that included that type of minimum monthly charge.

### CCA

CCA submitted that consolidated billing required consideration when customer care costs were allocated. CCA noted that consolidated bills reflected consolidation of individual delivery sites onto one bill. CCA suggested there were two definitions of customer bill consolidation. One was a billing summary that summarized a number of statements across several billing cycles with no impact on due dates or payment dates. The other, consolidated billing, was similar to summary billing except payment due dates were also consolidated.

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[74] Schedule "E" is benchmarking schedule

[75] DERS Application Volume 2, Appendix C, I-Tek MSA Schedule C – Fee Schedule, p. 3

[76] DERS Application Volume 2, Appendix C, I-Tek MSA Schedule C – Fee Schedule, page 6

[77] Gas and Electric

CCA submitted consolidated billing did not appear to reduce call centre contact. The Consumer Group therefore considered that it was inappropriate to assign customer care costs on the basis of consolidated bills, rather it should be done on the basis of the number of customers.

### Consumer Group

The Consumer Group noted that the provision of customer care services to DERS by I-Tek was governed by the MS Agreement. The Consumer Group noted that customer care costs constituted about 78% of the DERS non-gas DRT revenue requirement and about 70% of the DERS non-energy RRT revenue requirements.

### FMV of ATCO I-Tek Services

The Consumer Group argued that the evidence clearly indicated the unit rates negotiated for ATCO I-Tek services were generally higher than comparable benchmarks cited in evidence. Consumer Group also submitted there was no concrete evidence that indicated service levels were higher than those previously provided to ATCO Gas and ATCO Electric, or the service levels used for comparison.

The Consumer Group argued that although DEP would also obtain customer care services from ATCO I-Tek under the same terms as DERS, the Consumer Group submitted that was not a sufficient check and balance on the FMV of the MS Agreement terms and conditions. The Consumer Group suggested the MS Agreement should be evaluated as though it were a non arms-length transaction.

The Consumer Group argued that the initial negotiated prices for customer care services were not subject to an acceptable benchmarking study. The Consumer Group submitted that Dr. Chwalowski for PA Consulting acknowledged he did not have regard to the entire MS Agreement when he prepared his benchmarking report on behalf of DERS. Consequently, Dr. Chwalowski could not have factored some of the key provisions of the MS Agreement, such as the 10-year exclusive term and the price review provisions, into his assessment of the MS Agreement. Further, Dr. Chwalowski was unable to confirm whether the prices reflected in the MS Agreement were within the mid to high end of the lowest pricing quartile, a requirement for benchmarking under the MS Agreement when price reviews were carried out. Finally, Calgary's witness, Ms. Gogel, indicates she does not consider the PA study a proper benchmarking study.

Based on the foregoing, the Consumer Group submitted, that if the MS Agreement is approved, the Board should direct a benchmarking study to be completed at the earliest opportunity and that the Board should retain the ability to order benchmarking reviews, as appropriate, from time to time.

### Service Levels

The Consumer Group noted numerous references in the record discussed the higher service quality to be provided by DEML's contract with ATCO I-Tek, compared with ATCO's service levels, and that ATCO even suggested that might be a benefit of increased competition. However, the Consumer Group argued the record did not support such claims for either the call centre or billing functions.

### Base Billing Charge

The Consumer Group noted that the proposed $2.20 base billing charge was at the top end of the price range for billing services provided by DERS's external vendors. The Consumer Group referred to the DERS justification of the $2.20 ATCO I-Tek charge, related to ATCO I-Tek's provision of certain services, such as complex billing, exception handling and special services, that were not provided by other vendors.

The Consumer Group suggested that DERS explained what exception handling entailed, but was unable to identify what special services meant. The Consumer Group also noted that complex billing was limited to 2000 gas accounts with demand charges on the gas side. Based on the foregoing, The Consumer Group was not convinced these "services", alone, justified the I-Tek billing charges being at, or above, the top end of the scale for billing charges.

The Consumer Group noted that the PA Consulting evidence indicated a range of $1.80 to $1.93 for comparative billing charges. Dr. Chwalowski justified the higher base billing charge of $2.20 for ATCO I-Tek services due to the complex billing and more sophisticated CIS. Given the limit of 2000 on the gas side for complex billing accounts and similar limits on the electric side, the Consumer Group did not believe this item represented a significant cost factor, particularly given complex billings were only a small fraction of total service accounts.

The Consumer Group argued that regardless of whether the Board accepted the recommendation respecting duplication of customer database and billing runs, the billing charges proposed by DERS for retail billing were excessive. Consequently, the Consumer Group recommended billing charges should be based on a proper benchmarking study to be conducted at the earliest opportunity. Given the absence of specific benchmarks, the Consumer Group believed there was merit in considering some broad indicators of change in unit costs. The following was a comparison of all billing related costs for ATCO Gas South in 2002 compared with the amount forecast by DERS for 2004:

Table 15. Comparison of All Billing Related Costs

ATCO Gas South

| Year | 2002 |
|---|---|
| Customer billing and accounting AGS ($000) | 13,377 |
| Postage bill print stock, insertion of bills envelopes (Unbundling P 29) | -2,770 |
| Net | 10,607 |
| Average Number of customers | 419,637 |
| Average number of bills | 5,035,644 |
| Cost per bill | 2.11 |

DERS

| Year | 2004 |
|---|---|
| Total cost of billing services ($000) | 24,021 |
| System processing ($000) | 234 |
| Total | 24,255 |
| Average number of bills | 9,676,793 |
| Cost per bill | 2.51 |

The Consumer Group submitted that the higher cost per customer bill for DERS to be $2.51 in 2004 compared with ATCO's cost of $2.11 in 2002 was not explained. The Consumer Group argued the increase attributable to inflation, and any offset as a result of productivity improvements did not explain the increase.

The Consumer Group noted that the ATCO total billing costs also included the receipt and processing of raw metering information, a function not included for DERS. Further, the MS Agreement was an exclusive 10-year contract that should result in lower prices for the recipient of services. Therefore, the Consumer Group submitted the proposed base billing costs of $2.20 were excessive by 15%-20% and should be reduced accordingly.

### Call Centre Costs

The Consumer Group was concerned that the average call handling time of 330 seconds was significantly higher than the industry average and did not reflect efficiencies that could be achieved. The Consumer Group suggested a reduction in average handling time from 330 seconds to 240 (the high end of the industry average range) should be accompanied by a cost reduction of 27% to the unit cost per call. The Consumer Group also noted that the agent utilization rate reflected in the unit cost per call of $8.65 was 63.8%, whereas the industry norm appeared to be 65% to 70%. The Consumer Group suggested adjusting the utilization rate to at least the mid point of the industry norm should result in a reduction in the unit cost per call. Further, the Consumer Group noted that DERS did not forecast any interactive voice response (IVR) use. The Consumer Group argued the use of IVR might result in further efficiencies in call handling, not currently reflected in the forecasts. Therefore, the Consumer Group recommended these considerations be reflected in the unit cost per call approved by the Board.

The Consumer Group noted DERS's view that the deferral account would ensure customers only paid for the call center activity actually incurred. The Consumer Group argued that while that might be true, any efficiencies captured by I-Tek would not be passed along to customers. For example, if I-Tek was able to shorten the average call length as the Consumer Group recommended to 240 seconds, the existence of a deferral account would not pass the benefit of those savings on to ratepayers. As a result, the Consumer Group recommended the unit price per call be lowered to reflect reasonable levels of efficiency.

The Consumer Group suggested the record was unclear as to ATCO's current service level with regard to inbound calls. In principle, the service levels included in the MS Agreement were those in effect for ATCO Gas and ATCO Electric at the time the parties signed the agreement. The Consumer Group also observed that the service levels for inbound calls to be provided by DEML under the MS Agreement were not necessarily different from what ATCO currently provided.

The Consumer Group also noted that the 12-month rolling average percentage of calls answered in 20 seconds for ATCO Gas is 73.3%, a reduction from levels provided at the beginning of 2002. In 2001, ATCO Electric answered 75.25% of calls in 20 seconds. While the MS Agreement identified a service level of 80% answered in 20 seconds measured on a monthly basis, because the service level did not apply to call volumes greater than 115,500 calls, this standard would not apply during 28% of the months.[78] Thus, because of this call volume limit, the service level in the MS Agreement should not necessarily be interpreted as a higher level than the one previously achieved by ATCO. In addition, it should be noted penalties only applied if service levels fell below 72% in 20 seconds. The Consumer Group argued that was quite different from PA Consulting's characterization of a "rigid 80/20 schedule" with "strong penalties."

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[78] Based on past call volumes. If call volumes increase by 34% as projected, the standard would apply even less frequently. [Tr. p. 1498]

The Consumer Group was very concerned about proposals to lower service levels, even "slightly". That concern was only amplified as a result of DERS's reluctance to provide any estimates of the cost savings achievable from such a step. In the absence of any verifiable benefit, the Consumer Group submitted such a reduction in service only added to the harm incurred by customers as a result of the transfer transaction and DERS's application. The Consumer Group argued that potential harm to customer service should be measured with reference to levels to be provided by DERS as compared to those provided by ATCO, not with respect to what other utilities may or may not offer.

The Consumer Group noted that ATCO I-Tek service levels higher than industry norms related primarily to service levels for calls regarding credit and collections. The Consumer Group recommended that DERS should commit to providing less expensive service for credit and collections and should recoup the savings for ratepayers.

The Consumer Group suggested the whole arrangement with DEML lacked incentives to manage ATCO I-Tek costs efficiently. The whole contract was structured on the basis of cost flow-through to end customers. The subdivision of functions meant there were separate call center staff for calls to ATCO distribution, DERS regulated, DEML unregulated and credit and collections. The Consumer Group submitted that with the subdivided functions it was not possible to take advantage of economies of scale arguably achievable by combining different call patterns. While the Consumer Group did not advocate sharing of calls between regulated and unregulated entities, the use of ATCO I-Tek services was not designed with respect to making the most efficient use of resources.

**Billing Service Levels**

The Consumer Group suggested the evidence with respect to the MS Agreement appeared to provide for higher service levels than currently provided by ATCO with respect to certain billing and payment processing functions. However, the Consumer Group suggested the standards were not comparable because they did not measure the same thing.

The Consumer Group submitted measures for payment processing were also not comparable. Mr. Stephens acknowledged that his conclusion that DEML's service levels were higher was "due to the average measurement of the service level being monthly" in the MS Agreement. Despite the more frequent measurement levels, the Consumer Group was not convinced the new MS Agreement represented a higher overall level of service for billing and payment issues. Therefore, the Consumer Group supported Mr. Stephens' conclusion that DERS's increased Customer Care costs were largely due to increased unit costs, rather than higher service levels.

**Call Centre Volumes**

The Consumer Group noted that call center data provided for ATCO Gas for the period 1999 to 2002 indicated annual call volumes for all customer assistance calls of: 1999 – 685,900, 2000 – 1,114,500, 2001 – 1,175,100, and 2002 – 960,500. The Consumer Group also noted that the call types listed included Emergency, Re-Direct, Account Management, Utility Work, Budget Plan, Retailer and Other. About 73% of the calls were for Account Management, including calls related to the initiation, termination and transfer of accounts, billing amounts, rates and meter issues. The next largest category at 9% was Utility Work (e.g. service line installations, scheduling of field orders), followed by Re-Direct calls at about 6%.

The Consumer Group noted that DERS advised their forecast volumes were based on ATCO I-Tek historical call volumes as adjusted by DERS management. The consequence of the DERS management review was to add significant increases to the call volume forecasts once DERS took over the RRT and DRT function (i.e. an increase from 21% to 34% for the DRT volumes and 15% to 24% for RRT call volumes). The Consumer Group submitted that while DERS indicated the rationale behind the increases was to account for call volume increases during anticipated high gas price periods, DERS did not indicate what it used as parameters for determining "high gas price periods." In addition, the Consumer Group argued that basing the call volumes on ATCO's total call centre statistics resulted in an overstatement of call volume, as it would include calls related to both the distribution and retail business. If both ATCO Gas and DERS included these calls in their rate applications, ratepayers would be funding the costs twice.

If there were no problems with customers' meter reading and billing accuracy as promised by DERS, there should be no additional cause for customers to call. However, customers were concerned calls for DEP would be included in the call centre volumes and costs. For example, the category of 'Re-Directs' related to the transfer of calls to another area or person when the customer assistance centre was unable to assist the caller and was of particular concern. The Consumer Group suggested these calls might come into the DERS call centre due to customer confusion with DERS and DEP. The Consumer Group stated that regulated customers should not pay for these calls, and that DEP should be segregated, reported separately and all handling costs should be excluded from the regulated revenue requirement.

The Consumer Group noted that the DERS sample bill showed a customer assistance centre phone number and an emergency and service request phone number. With both ATCO and DE's logo and name on the bill, customers would be confused whose customer assistance centre they were calling. Unless it was an emergency, customers would likely call the customer assistance centre for all other matters. If DEML was active with advertising, billing envelope inserts, etc for the marketing of their retail energy contracts and other unregulated home services, customers would likely assume the one call centre will reach all. Therefore, in addition to reducing the call volume forecast, the Consumer Group submitted the bill statement should more clearly state what services would be available by calling the DERS customer assistance centre. The Consumer Group suggested that should result in a substantial reduction to the forecast of call volumes in the range of 30-40% from the levels DERS forecast for the 2003 and 2004 revenue requirement. This level of reduction should be applicable to both the RRT and DRT.

### Deferral Account

The Consumer Group suggested there was little incentive to manage the I-Tek costs efficiently since the whole contract was structured as a cost pass-through. The Consumer Group noted that DERS indicated its incentive was to manage actual costs in relation to forecasts, however the forecast billing determinants for a number of items were not established in relation to historical determinants. The Consumer Group recommended that DERS should be directed to re-file the billing determinants in Schedule BR.DERS-15(c), and should identify the historical billing determinants for all items, as applicable. If the forecasts were higher than historical, DERS should be directed to provide justification for the change. DERS should also be directed to structure its management incentive package so management had an appropriate incentive to manage and minimize each controllable customer care cost.

## HVAC

### FMV of ATCO I-Tek Services

HAVC argued there was a lack of evidence to justify costs arising from the MS Agreement. HVAC noted that DERS relied on the evidence of Ms. Sheri Strain and a report prepared by PA Consulting Group to demonstrate the reasonableness of the proposed pricing and costs arising under the MS Agreement.

HVAC submitted that while the Strain Evidence provided some pricing information about other DEML customer care outsourcing arrangements in which the company has had experience with, none of these agreements could be disclosed due to confidentiality provisions. As a result, the Strain evidence simply provided selective information about the other DEML arrangements that were known to be unique in nature and no objective, independent review of them as compared to the MS Agreement was carried out.

HVAC submitted that Dr. Chwalowski, appearing as an independent expert witness on behalf of DERS was not provided with the opportunity to review DEML's other agreements as such as exercise was not part of his retainer. HVAC stated that Dr. Chwalowski's report was comprised of a series of presentation slides, and not what one would commonly expect as an expert report. HVAC referred to several other aspects of Dr. Chwalowski's report that HVAC considered to be lacking. HVAC suggested that proper due diligence was not performed, and that important portions of the MS Agreement were not reviewed by Dr. Chwalowski. HVAC argued that no weight should be given to Dr. Chwalowski's report, or to his testimony.

As a result, HVAC submitted the Board could not, without proper evidence, approve the applied-for charges associated with the MS Agreement.

### Call Centre Costs

HVAC submitted that the "per call charge" fee ATCO I-Tek intended to charge DERS was problematic. HVAC noted that there was a maximum $10 fee when anyone called the billing account information phone number, which appeared on the first page of the DERS bill. HVAC submitted the fee would be incurred for ATCO I-Tek simply answering that call. HVAC noted that the justification for the charge was simply that it was a negotiated item and that no specific reason could be provided by DERS.

HVAC suggested there were at least two problems with the arrangement. The first arose because DERS's bill would also include the ATCO Gas Distribution bill. The second concern related to calls made to the call centre in respect of other information that was contained in the billing envelope.

HVAC suggested that materials and information other than the regulated services bill would be included in the billing envelope. HVAC also suggested it was clear that should anyone call the DERS billing inquiry number, a fee was levied and recovered by regulated service ratepayers. HVAC argued the arrangement had unacceptable cost consequences.

HVAC submitted it was reasonable to expect customers to call a billing inquiry phone number about information provided to them in the billing envelope, particularly when such information was branded with the same logo and design as DERS. HVAC stated that co-branding and billing envelope control coupled with the per call charge fee created the real risk that regulated service would accrue higher costs than would otherwise be necessary or appropriate. HVAC argued the per call charge provision should be rejected in its entirety.

HVAC suggested the Board should question whether confusion arose and if so, whether any related costs could be avoided by requiring DERS to arrange its affairs differently. However, should the Board allow outsourcing to be provided under the terms of the MS Agreement, the Board should impose and maintain regulatory controls over the price re-determination provisions.

### Views of DERS

The customer care costs included in the DRT and RRT non-energy revenue requirements were simply the mathematical result of the application of the I-Tek MS Agreement unit prices for each activity to the utilization forecast for each activity.[79] The forecast revenue requirements included in the DRT and RRT for customer care costs are shown in Tables 12 and 8 respectively. DERS submitted that these costs were underpinned by market-based unit pricing and rational and considered utilization forecasts. Therefore, the forecast revenue requirements should be approved as filed.

### FMV of ATCO I-Tek Services

DERS also defended its review of the MS Agreement. DERS submitted that the Shari Strain Evidence demonstrated that DEML conducted internal due diligence to review services, service levels and whether unit pricing fell within FMV. Furthermore, in the Retail Sale, DEML's stated the decision to enter into the MS Agreement was with the objective of seeking a seamless transition for customers of ATCO.

DERS referred to the evidence of Dr. Chwalowski of PA Consulting Group. Dr. Chwalowski submitted that ATCO I-Tek offered standard customer services typical of utility requirements in North America, and offered the whole suite of customer services compared to vendors that individually offered a subset of those services.

DERS replied to Calgary's question as to why DERS did not present a witness from ATCO I-Tek to speak to issues related to the MS Agreement. DERS submitted that Calgary's question was nothing more than a tactic to divert attention away from the key facts established on the record concerning the FMV of the pricing of the MS Agreement services and the appropriateness of the contracted service levels.

DERS stated that while the MS Agreement was a 10-year agreement, there was provision for three price reviews by each party, and thus would remain market based over the life of the agreement. Changes in postage and paper costs were charged on a pass-through basis, providing consumers with any cost efficiencies gained in these areas.

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[79] Tr. p. 1053

DERS submitted that prior to entering into the MS Agreement with ATCO I-Tek, DEML conducted a review of the services scope, service levels, pricing level and facilities and resources that ATCO I-Tek would use for the provision of customer care services.[80] A key component of the due diligence conducted by DEML prior to its execution of the MS Agreement involved a comparison of the unit prices and corresponding services and service levels to respective prices and services for similar outsourcing agreements in place between DEML and other vendors. DEML stated that based on that comparison, the overall terms and conditions of the MS Agreement and the fact that ATCO I-Tek possessed the experience, capabilities, facilities and resources necessary to enable DERS to deliver a level of service in Alberta that was consistent with its commitment to the provision of excellent customer care, DEML chose to enter into the MS Agreement with ATCO I-Tek.

Dr. Chwalowski submitted that while the MS Agreement pricing scheme for some services was different from typical vendor offerings, pricing under the MS Agreement was in the range of FMV for utility customer services.

Further, DERS submitted that, based on the evidence of Dr. Chwalowski and DEML's own internal comparative analysis, the pricing under the MS Agreement, having regard to the services and the service levels, was within FMV. DERS argued that even Ms. Gogel conceded that, based on her report, she was not able to conclude that the MS Agreement services were priced outside the market range.[81] DERS argued the best evidence on the record was the report prepared by Dr. Chwalowski, as Dr. Chwalowski's report was prepared using a much larger data sample than was the case for the Platts Consulting Report prepared by Ms. Gogel.

DERS argued that Mr. Stephens evidence was flawed. DERS suggested the Board should keep in mind that Mr. Stephens did not compare the service levels provided for under the MS Agreement against the service levels for the same services of Enbridge and BC Gas, that he used as the basis for his conclusion.[82] DERS also suggested Mr. Stephens acknowledged that in order to arrive at valid comparisons concerning FMV, it was necessary to ensure that the comparison involved the same or substantially similar services at the same or substantially similar service levels.[83] DERS argued Mr. Stephens did not possess the necessary data or expertise[84] to substantiate his conclusion concerning FMV.

DERS argued that a presumption of prudence should apply in respect of the MS Agreement and that the costs associated with those services should be considered just and reasonable. This was supported by the fact that Direct Energy Partnership will incur the same ATCO I-Tek MS Agreement charges as DERS.

DERS replied to Calgary's suggestion that the cost consequences of the ATCO I-Tek MS Agreement must be vetted in full.[85] DERS argued that full vetting occurred through the course of the information request process and cross-examination during the hearing. DERS submitted that the unit pricing established in the MS Agreement should be accepted by the Board as being within FMV for similar services at similar service levels.

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[80] Exhibit 002-01, Volume 2, Appendix D, p. 1
[81] Tr. p. 1553
[82] Tr. pp. 1566-1567
[83] Tr. p. 1560
[84] Tr. pp. 1567-1568
[85] Calgary Written Argument, p. 12

### Minimum Billing Charge

DERS submitted that Calgary neglected to include the fact that DEP would also use ATCO I-Tek in their analysis of the minimum monthly charge provision. DERS noted that the minimum monthly charge provision applied to all DEML users under the MS Agreement. DERS suggested that Calgary's supposition was unreasonable and assumed that all customers that left the RRT or DRT took service from competitive retailers other than DERS's affiliates. Furthermore DERS suggested it also assumed that DERS's unregulated affiliates failed to attract any other non-regulated customers. DERS concluded that was implausible, as the sum of both DERS and DEP service accounts would have to reduce by 22.5% for the minimum charge provision to take effect.

### Service Levels

DERS noted that Mr. Stephens agreed the service levels prescribed in the MS Agreement were as good as or better than the service levels in the current ATCO I-Tek MS Agreement with ATCO Gas and ATCO Electric. DERS submitted that Ms. Gogel agreed the MS Agreement service levels were higher than average, but not out of the range for utility industry[86] and also supported the conclusion of Dr. Chwalowski on that point. Further, DERS noted that Ms. Sharpe acknowledged that during the applied-for test periods, "a higher level of service standard is a reasonable issue as long as it's provided cost effectively."[87] DERS also submitted the service levels prescribed in the MS Agreement surpassed the service levels set out in the Board's draft Regulated Services Provider, Service Quality and Reliability document.[88]

Dr. Chwalowski submitted that ATCO I-Tek operated under a more complicated and rigid set of service levels than most clients required. Dr. Chwalowski also submitted the MS Agreement required a higher standard of personalized customer service than was typical for these types of outsourced arrangements in the utility industry. DERS argued that the service levels provided for under the MS Agreement were appropriate.

DERS replied to the AUMA/CE suggestion that increased service levels under the MS Agreement were not warranted or necessary, and should be adjusted to previous ATCO levels, until such a time when surveys and customer input determines there should be increased service levels. DERS also replied to the AUMA/CE suggestion that the service levels and increased costs were done for the ultimate benefit of DEP.[89] DERS defended the service levels and stated that DERS was committed to providing superior customer service and chose to enter into the MS Agreement in order to facilitate a seamless transition and to mitigate any difficulties that have been experienced by other service providers to date. DERS argued the service levels within the MS Agreement were not out of range for the utility industry and both the regulated and unregulated customer base would benefit from the high service levels that would be provided by ATCO I-Tek.[90]

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[86] Exhibit 03-06, p. 22; 15 Tr. p. 1560

[87] Tr. p. 1643

[88] Application No. 1299855, Tr. p. 1390

[89] AUMA/CE Written Argument, p. 19

[90] Written Argument of DERS, pp. 11-13

## Utilization Rates

DERS submitted that the forecast utilization rates for the various activities under the MS Agreement were based on historic utilization rates adjusted by the judgment and experience of DERS staff where applicable.[91] Activities related to billing services, walk-in services, pass-through charges, and credit management were primarily driven by the number of service accounts processed, or the number of bills issued. The utilization forecast for these items was based on the forecast number of service accounts and bills. These forecasts were based on historic ATCO Electric service accounts and bills, adjusted for forecast customer increases and forecast switch rates.

The historic call centre utilization figures were subject to analysis by DERS staff, and the forecasts underlying the costs in this area were adjusted based on the judgment of those staff. DERS recognized that during the upcoming transition period, wherein customers would be presented with a new bill format and a new service provider, and despite the mitigating impact of the company's proposed consumer education program, there would be increased call centre activity. DERS submitted that there would be an increase in the number of calls and an increase in the duration of the average call. DERS stated that the activity level during those periods was subject to an adjustment based on the experience of DERS staff with similar transition periods in the energy market in Alberta.[92] The final result is that for the 5-month test period, call volumes were forecast to increase by 24% above long-term trends, and were forecast to decrease in the 12-month test period to a level 15% above long-term trends. In addition, call duration was forecast to be 20 seconds longer than historic trends.[93]

## Call Centre Costs

DERS noted that the Consumer Group suggested the average call handle time should be reduced from 330 seconds to 240 seconds to reflect "industry averages", and that that reduction would be accompanied by a 27% reduction in the cost per call.[94] DERS submitted that position was inconsistent with DERS evidence that call handle time would increase through the transition period.[95]

DERS replied to the Consumer Group suggestion that customer care costs should be adjusted downward to reflect IVR use. DERS argued that suggestion could only be implemented if the DERS revenue requirement also reflected the costs to install IVR.

DERS also rejected the Consumer Group suggestion that there should be some form of tracking, segregation, and extraction of the cost of calls related to DERS's unregulated affiliates.[96] DERS argued that the average consumer deserved more credit than their representatives appeared to give them. DERS stated that they did not have the ability to allocate the cost of all misdirected calls to the intended recipient, and it seemed patently prejudicial to only allocate the costs of misdirected calls to its unregulated affiliates.

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[91] Tr. pp. 1284-1287

[92] Tr. pp. 1457-1461

[93] Exhibit 002-01, RRT Application, pp. 6-4 – 6-5

[94] Consumer Group Written Argument, p. 20

[95] Written Argument of DERS, pp. 34 – 35

[96] Consumer Group Written Argument, p. 25

### Deferral Account

DERS suggested it was important that DERS proposed a deferral account for the entirety of the costs related to customer care, which were those costs under the MS Agreement.[97] DERS argued that treatment would ensure that, to the extent that DERS's switching forecast was inaccurate and additional or fewer service accounts and bills were processed and mailed, customers would pay only those costs actually incurred. In addition, DERS submitted the deferral account would ensure that in the event the call centre activity was either greater or lower than that forecast by DERS, customers would pay only those costs actually incurred.

DERS argued that the Consumer Group's suggested 30 – 40% reduction to forecast call volumes was unsupported. DERS submitted its evidence demonstrated that call volumes would increase during the transition period.[98] DERS suggested that the deferral account proposed by DERS for customer care costs, would ensure that customers pay only for those costs incurred to provide service.[99]

### Views of the Board

In sections 3.3.2 and 4.3.2 of this Decision, the Board has approved the use of deferral accounts for RRT and DRT customer care costs. Accordingly, the Board does not consider it necessary to address the forecast volumes used in the determination of customer care costs.

With respect to the service levels established in the MS Agreement, the Board notes that the service levels appear to be higher than the current service levels of ATCO Electric and ATCO Gas. However, the Board also notes that Ms. Gogel and Dr. Chwalowski both agreed that the service levels in the MS Agreement were not out of the range for the utility industry. The Board further notes that Ms. Sharp, on behalf of Calgary, agreed that higher standards of service might be reasonable during the test period if provided cost effectively.

The Board is cognizant of the importance of a smooth transition from ATCO to DERS. The Board therefore considers that the proposed service levels are reasonable for the purposes of this Decision.

With respect to the unit costs of the customer care services set out in the MS Agreement, the Board notes the position of interveners such as the Consumer Group that the base billing charge and the call centre cost per call appear to be higher than fair market value. The Board notes that the base billing charge of $2.20/customer/month is approximately 14% above the high end of the range identified by Dr. Chwalowski.

However, in the Board's view it is the overall cost to customers, not the cost of individual customer care services, that should be considered when assessing fair market value. In this regard, the Board notes the evidence of Ms. Gogel on behalf of the Calgary that she could not conclude that the overall costs of the MS Agreement were unreasonable.[100] The Board also notes that DEP, which has every incentive to minimize its costs, will be paying the same charges as DERS under the MS Agreement.

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[97] Tr. pp. 1287-1288

[98] Written Argument of DERS, pp. 34 – 35

[99] Written Argument of DERS, p. 35

[100] Tr. p. 1553

Nonetheless, the Board considers that the evidence with respect to the appropriateness of the ATCO I-Tek charges is inconclusive, and the Board is not fully satisfied that the prices charged by ATCO I-Tek under the MS Agreement represent fair market value.

Therefore, for the purposes of this Decision, the Board will establish a placeholder for customer care costs by reducing DERS's proposed revenue requirement for customer care costs by 10%.

Furthermore, the Board directs DERS to undertake a comprehensive benchmarking study to determine if the charges under the MS Agreement represent fair market value for the services provided and if not, what the fair market value is for the services. Once the Board has completed its review of the benchmarking study, the Board will replace the placeholder for customer care costs based on fair market value.

The Board considers that the benchmarking study should be filed with the Board as soon as practicable in order to minimize the magnitude of any required rate adjustments. The Board notes that ATCO Gas and ATCO Electric are also both subject to outstanding Board directives to benchmark their ATCO I-Tek customer service costs, and the Board urges DERS to consider collaborating with ATCO Gas and ATCO Electric with respect to the benchmarking process in order to increase the efficiency and reduce the costs of the various benchmarking requirements.

### 4.1.1.2 Amortization of Integration Costs

DERS's forecast amortization expense for integration costs for the RRT and DRT are set out in Tables 7 and 11 respectively.

DERS proposed that operating integration costs be recovered during the test period and that capital integration costs be amortized over a five-year period.

#### Views of the Interveners

#### AUMA/CE

AUMA/CE did not oppose the five-year amortization period for capital related integration costs. With respect to operating related integration costs, AUMA/CE noted that DERS would have either a 13 or 12 month test period depending on when DERS actually commences providing service. AUMA/CE argued that operating related integration costs should extend beyond the test period and recommended that the amortization period for the operating related integration costs should be 25 or 24 months.

#### Calgary

Calgary argued that DERS provided no evidence to support its selection of the amortization periods.

Calgary submitted that if the Board allowed any component of the proposed integration costs, they should be considered as start-up in nature and, therefore, relate to the long-term operation of DERS. Calgary considered that a period of 10 years would be appropriate.

**Consumer Group**

The Consumer Group did not object to the use of a five-year amortization period for capital related integration costs.

**Views of DERS**

DERS stated that the 17-month amortization of operating integration costs, and its operating delay costs was reflective of the two applied-for test periods, and the period in which the costs would be recovered through rates.

DERS submitted that the majority of capital costs were related to information technology assets that had a forecast useful life of five years and that a corresponding amortization period was appropriate.

**Views of the Board**

Since the Board has not approved DERS's request for recovery of operating integration and delay costs, there is no need to address an appropriate amortization period for such costs.

With respect to capital related integration costs, the Board notes that the majority of these costs are related to information technology. The Board agrees with DERS that a forecast useful life of five years is reasonable for information technology and the Board therefore accepts that a five-year period is appropriate for the amortization of such costs for the DRT and RRT.

#### 4.1.1.3 Working Capital Costs

DERS's forecasts of non-energy working capital costs for the RRT and DRT are set out in Tables 7 and 11 respectively.

The Board has addressed the appropriate rate to be used for working capital in section 2.6. The Board will address DERS's request for deferral account treatment of working capital in sections 3.3.2 and 4.3.2.

As discussed in section 4.1.1.5, the Board will not include an allowance for hearing costs in the forecast working capital requirements.

Other than this adjustment for hearing costs, the Board notes that no intervener commented on DERS's proposed method of calculating working capital. Other than this adjustment for hearing costs, the Board considers DERS's proposed method of calculating working capital to be reasonable and accepts DERS's proposed method for the purposes of the RRT and DRT in this Decision.

#### 4.1.1.4 Credit Charges

DERS's forecast of non-energy credit charges for the RRT and DRT are set out in Tables 7 and 11 respectively.

Non-energy credit charges are related to the credit support requirements under the MS Agreement between DEML and I-Tek.[101] Under the MS Agreement, DEML's parent, Centrica plc, must post either an irrevocable and unconditional guarantee or an irrevocable Letter of Credit in the amount of $30.0 million for termination charges[102] and $15.0 million in support of operating charges.

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[101] Pursuant to clause 8.11(b)(ii) of the MSA

### Views of the Interveners

### AUMA/CE

AUMA/CE did not agree that the Board should approve Parental Guarantee charges but recommended a lower amount if the Board approved such charges. AUMA/CE submitted that any such charges should be shared between ATCO Electric and ATCO Gas in the same proportion as proposed by DERS.

### Calgary

Calgary submitted that ATCO required Parental Guarantees for the MS Agreement because it had low confidence in the financial capability of DEML. Calgary argued that the cost of the Parental Guarantees for the I-Tek MS Agreement should not be included in the revenue requirement since it was a cost that arose out of the agreements negotiated between ATCO and DEML related to the Retail Sale.

### Views of DERS

DERS submitted that the proposed credit charges were the mathematical result of the applied for rate of 40 bps for the Parental Guarantee to the forecast requirements for a Parental Guarantee under the MS Agreement between DEML and I-Tek.

DERS indicated that it allocated its Parental Guarantee charges associated with the MS Agreement between the RRT, DRT and DEML unregulated businesses based on its forecast of the total number of customers in the respective businesses.

### Views of the Board

The Board notes the Calgary's argument that the cost of the Parental Guarantees for the I-Tek MS Agreement should not be included in the revenue requirements since it was a cost that arose out of the agreements negotiated between ATCO and DEML related to the Retail Sale. However, as discussed in section 2.2, the Board is of the view that it must consider the reasonableness of DERS's costs on a stand-alone basis.

The Board considers that it would be a normal business practice for parties to an agreement to assess the credit risks associated with an agreement and determine whether credit support is required from the counterparty. In this case, the Board considers the provision of credit support by DERS to ATCO I-Tek to be reasonable.

With respect to the amount of credit support that must be provided by DERS, the Board notes that the $45,000,000 of total credit support represents about 80% of the forecast 2004 customer care costs for the DRT and RRT. The Board also notes that the amount of credit support was determined through negotiation between ATCO and DEML.[103] The Board considers the amount of credit support to be provided by DERS to be reasonable.

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[102] With respect to termination charges, $30.0 million must be posted for years one through six, thereafter reducing by $5.0 million per year to $10.0 million in year ten.

With respect to the proposed form of credit support, the Board notes that DERS has proposed to use a Parental Guarantee at a cost of 40 bps. The Board notes that this cost is less than the cost of providing a Letter of Credit. Therefore, the Board will approve, for the test period, a rate of 40 bps for the cost of the credit support provided to ATCO I-Tek.

The Board will accept DERS's forecast of the non-energy credit charges as set out in Tables 7 and 11.

The Board will address DERS's proposal for deferral account treatment of these costs in sections 3.3.2 and 4.3.2.

#### 4.1.1.5 Amortization of Hearing Costs

DERS's forecast of hearing cost expense for the RRT and DRT are set out in Tables 7 and 11 respectively.

DERS proposed to allocate hearing cost expense equally between the RRT and the DRT. DERS also proposed that its total forecast hearing costs for this proceeding be recovered during the test period.

**Views of the Interveners**

**AUMA/CE**

AUMA/CE submitted the amortization period for the hearing costs should be the same as that it proposed for the operating integration costs, being a period of 25 or 24 months, depending on when DERS commenced operations.

**Calgary**

Calgary noted that DERS suggested that the level of hearing costs were a function of the degree of participation by the various parties, including the volume of information requests. Calgary asserted that the costs were driven more by the lack of information in the Application, refusal to provide information in the information request process and the frequency of updates, corrections and errata.

Notwithstanding that DERS stated that its hearing costs estimate was for the current proceeding, Calgary expressed concern that no costs should be included in respect of the Application, whether in the hearing cost reserve or elsewhere, for costs incurred by DERS or any of its affiliates for participation in the ATCO Retail Sale proceeding.

Calgary noted that for its hearing cost reserve account, DERS had included $500,000 as its opening balance for each of the DRT and RRT and that DERS had included unamortized hearing cost amounts in its working capital and amortization of hearing costs in its revenue requirement. Calgary suggested that DERS's approach was tantamount to saying that DERS was investing $1 million in hearing costs as of August 1, 2003. Calgary stated that it was unaware if any costs with respect to intervener participation, or DEML participation, were submitted to the Board to approval. Therefore, as there was no investment, Calgary submitted that there was no need to reflect carrying costs on any amount with respect to hearing costs in the working capital calculation.

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[103] CAL-DERS-47

### CCA

The CCA considered that hearing costs should be allocated based on an assignment of 50% of the costs to customers and 50% to energy. The CCA also considered this allocation of costs to be reasonable and simple and would ensure larger customers picked up a fair share of their costs. The CCA submitted that to assign the costs on the basis of customers would cause residential customers to bear too great a share.

### Consumer Group

The Consumer Group submitted that DERS's proposal gave rise to two key issues: the appropriateness of the 50/50 split of hearing costs between the RRT and DRT, and the appropriateness of the period of amortization.

The Consumer Group argued that the 50/50 split was not equitable given that a smaller number of electric customers must bear the same costs as a much larger number of gas customers. Notwithstanding DERS might have put the same effort put into the DRT and RRT filings, the Consumer Group considered that this did not accord with the general impression of the hearing that the DRT application took more hearing time due to its unique nature. The Consumer Group submitted that a direct allocation of costs between the DRT and RRT was not possible simply because both the DRT and RRT application were part of the same hearing process. Rather, a suitable proxy for allocation between the two tariffs would be one done on the basis of customer numbers.

The Consumer Group disagreed with DERS's proposal to amortize the entire amount of forecast hearing costs within one test period. The Consumer Group submitted that:

- this proposal was inconsistent with the treatment of hearing costs by other utilities, such as ATCO Gas and ATCO Electric;
- the period of amortization proposed was not appropriate where a company was intending to carry on business for more than one test period; and
- because this was DERS's initial application before the Board, the costs may be somewhat higher than in subsequent applications of the same scope.

Consequently, the Consumer Group suggested a more appropriate amortization of forecast costs would be over a period of five years. The Consumer Group submitted that $200,000 per year should be allowed for amortization of hearing costs for the test period, the sufficiency for which could be reviewed at the time of DERS's next application when actual hearing costs are known.

### Views of DERS

DERS forecast hearing costs of $500,000 related to each of the RRT and DRT applications, and proposed to amortize these costs over the requested test periods. DERS considered that the forecasts were reasonable based on a review of other EUB cost orders.

DERS submitted that although the DRT appeared to take considerably more time during the hearing than the RRT, most of the issues discussed in respect of the DRT would also have been discussed in an RRT-only proceeding. DERS also noted that the RRT has System Settlement costs, annual energy cost reconciliation and 7 rate classes whereas the DRT had 3 rate classes, monthly Deferred Gas Account (DGA) and a more robust gas procurement requirement. DERS therefore considered that a 50/50 allocation of hearing costs between the RRT and the DRT was appropriate.

**Views of the Board**

Given that the test period approved by the Board will be a maximum of one year, the Board expects DERS to file its next application before the end of 2004. Accordingly, the Board considers that it would be appropriate to recover the hearing costs associated with this proceeding within the approved test period.

The Board agrees with DERS that although much of the hearing was focused on matters raised by interveners in the context of DRT issues, it is not evident that the matters being discussed were applicable only to the DRT. The Board accepts for the purposes of this Decision that the hearing costs should be allocated 50/50 between the RRT and the DRT.

The Board will therefore include in the approved revenue requirement an amount of $500,000 for each of the RRT and DRT.

The Board agrees with Calgary that DERS has inappropriately included the forecast of hearing costs as an opening balance in the determination of working capital. The Board expects DERS to include its actual balance in the hearing cost reserve account in its determination of its actual working capital requirements. To determine the balance in the hearing cost reserve account, the Board expects DERS to recognize one-twelfth of the approved annual funding of $500,000 each month and to deduct payments made in accordance with Board cost orders, at the time that any such payments are made. If, for example, total payments of $500,000 were made mid-year, the average annual contribution to working capital would be zero.

For the purposes of establishing the forecast revenue requirement, the Board will assume the average contribution to working capital in respect of hearing costs is zero. The Board notes that actual working capital costs will be subject to deferral account treatment, as discussed in sections 3.3.2 and 4.3.2.

### 4.1.1.6 Other Operating Costs

DERS's forecast of other operating costs for the RRT and DRT are set out in Tables 7 and 11 respectively. The Board notes that DERS did not seek deferral account treatment for these costs.

**Staff Salaries**

With respect to the RRT, DERS indicated that it required 7.72 FTEs, all allocated to the non-energy revenue requirement.

With respect to the DRT, DERS indicated that it required 21.04 FTEs, with 4.90 FTEs and 16.14 FTEs allocated to the energy and non-energy revenue requirements respectively.

### Views of the Interveners

### AUMA/CE

The AUMA/CE noted the annualized average salaries for RRT staff for 2003 and 2004 of $148,000/FTE and $155,000/FTE, respectively, and considered the proposed cost/FTE to be overstated. AUMA/CE also noted that while DERS was asked to provide the basis for the salaries, benefits and bonuses, it did not provide such information as evidence to substantiate its forecast cost/FTE.

AUMA/CE submitted that the numbers provided for the other three major utilities operating in Alberta were significantly less than the average base salary of $101,646 for 2003 and $106,220 for 2004 forecast by DERS. Assuming benefits of 30%, AUMA/CE compared DERS salary proposals with those determined for 2003 of $94,900/FTE and of $69,719/FTE for ATCO Electric and ATCO Gas, respectively.

AUMA/CE recognized that the unregulated functions performed by some of the DERS staff might require more experienced and qualified personnel to maximize profit of the unregulated businesses. AUMA/CE submitted that regulated customers should not cross-subsidize the unregulated businesses by paying higher salaries for regulated FTEs.

While DERS may argue that its "weighting" of senior management and executive to other staff was higher than that of the utilities making comparisons less useful, AUMA/CE submitted ATCO Electric was previously providing this retail function with an apparent lower senior management/executive to staff ratio. AUMA/CE questioned the need of such a high ratio of senior management to staff in a business that was not set-up to generate a profit.

AUMA/CE submitted that DERS's proposed base salaries for 2003 and 2004 were excessive. AUMA/CE further submitted an appropriate salary and benefit level for the RRT function for DERS was $76,600, which was the average of the 2003 ATCO Gas and ATCO Electric calculated salaries, plus 30% for benefits, and the average AltaLink number of $65,000. AUMA/CE submitted that this calculation was liberal, generous and reasonable given that the numbers for ATCO Gas and ATCO Electric may possibly include benefits. AUMA/CE recommended a reduction to the salaries and benefits costs of DERS on an annualized basis of $275,699.

AUMA/CE further submitted that the corporate costs should also be reduced to recognize the overstated salaries and benefits. AUMA/CE submitted that an additional annualized amount of $43,659 be reduced from the Corporate costs.

AUMA/CE noted that the average bonuses proposed by DERS were in the 30% range. Citing a lack of information being provided, AUMA/CE submitted that DERS should not be entitled to charge customers for the full amount of the bonus amounts requested in the Application in the recognition that a component of the bonus structure was related to economic profit of DEML. AUMA/CE submitted this was unlikely to be of benefit to regulated customers, and that the amounts requested were discretionary and may not be fully disbursed. AUMA/CE recommended an average bonus percentage of 15% to be paid by customers through regulated rates, resulting in an annual bonus amount of $11,490/FTE. AUMA/CE also recommended a 15% bonus for corporate salaries.

With respect to the FTE allocations between the regulated and unregulated divisions of DEML, AUMA/CE submitted the following:

(i) AUMA/CE considered that the VP Electricity had little requirement to do work in the Alberta regulated market and that no allocation to the regulated function should be made.

(ii) With respect to the Finance/Accounting area, AUMA/CE submitted that given the difference in the size of the regulated versus unregulated business at the current time and the apparent high fixed set-up cost for accounting system, the allocation should be 60% regulated / 40% unregulated and, within the regulated function, 50% Gas / 50% Electric, since the time spent on each would likely be the same.

(iii) Noting that the VP Finance EMG description lacked any reference to a regulatory role and considering that the qualifications were in excess of those required in the regulated function, the VP Finance EMG function should be allocated 10% regulated / 90% unregulated.

(iv) AUMA/CE considered that the VP Marketing position showed very little requirement for a "regulated" background but instead was intended to benefit the unregulated businesses for which a more reasonable allocation would be 10% / 90% regulated/unregulated. As the description of the Market Analyst (regulated) position did not provide any insight for an appropriate allocation, AUMA/CE submitted that a 50/50 allocation would be reasonable.

(v) With respect to the "Business Development" position, as the job description showed some utility activity, AUMA/CE recommended that the allocation to the regulated function should be 25%, split equally between gas and electric.

(vi) With respect to the Communications area, as the job description did not appear to list any significant "regulated" skill requirements or job duties, AUMA/CE recommended that the cost allocation should be 50/50 regulated/unregulated.

(vii) With respect to the Senior Management area, based on the job description, AUMA/CE recommended that the allocation should be 25%/75% regulated/unregulated.

(viii) With respect to the Risk Management area, AUMA/CE recommended that the Executive Assistants have their time allocated 10%/90% regulated/unregulated, the same as the Director.

AUMA/CE noted that DERS did not keep timesheets to record regulated activity nor did it conduct any other studies to attempt to measure the time spent on the regulated versus unregulated functions. AUMA/CE recommended that DERS be directed to either keep time sheets or conduct sample, or time in motion studies to more quantitatively support its allocations in its next filing.

### Calgary

Calgary was concerned with the allocation of costs between regulated and unregulated entities and the levels of compensation used by DERS, particularly with the potential for DERS to subsidize unregulated affiliates through its rates and tariffs. Calgary submitted that:

- DERS lacked experience in forecasting allocations in the regulated Alberta market; or in allocating costs or forecasting allocations between regulated and unregulated entities;
- the allocations made by DERS were excessive and unreasonable for the regulated business, particularly given that the cost per full time equivalent (FTE) position allocated to DERS was approximately 150% higher than the cost per FTE used by ATCO Gas;
- there was a disproportionate number of positions in a senior management capacity for a regulated business;
- assertions made by DERS that salaries were market based were unsupported, noting that DERS chose not to table either the Mercer Report or the Towers Perrin Report upon which it allegedly relied;
- amounts for bonuses should not be included for staff, or for executives, performing regulated services because the amounts were predicated on the bonus structure for the unregulated side of the business and were contingent on objectives being met; and
- as there was no objective information to support the claim for the 4.5% inflation factor for labour, the inflation rate to be allowed for DERS should be no higher than 3.25%, which the Board allowed for ATCO Gas in its recent 2003/2004 GRA.

Calgary submitted that the validity of labour cost allocations made by DEML to DERS were questionable because of the lack of disclosure by DERS of the underlying allocation data, without which a review and evaluation could not be conducted. Calgary submitted that until DERS could demonstrate otherwise, the cost allocations of staff proposed by DERS should be reduced by 50%.

### Consumer Group

The Consumer Group was concerned with both the salary structure and the management structure proposed by DERS but acknowledged some increased salary costs may be warranted due to additional functions being performed. However, the Consumer Group submitted that salary costs proposed by DERS were excessive and noted the following:

- ATCO Gas charged 11 FTEs to the GCRR for portfolio management and related administrative activities while DERS proposed to include 21.84 FTEs in the revenue requirement for similar functions.
- The finance and retail settlement function proposed by DERS included 6 FTEs, including a new Retail Settlement function not previously performed by ATCO Gas; however, a significant part of the customer accounting, credit and collections and reporting, including management of the budget payment plan, would be carried out by ATCO I-Tek.
- The operations function, which was primarily the oversight of the ATCO I-Tek MS Agreement as well as interacting on behalf of customers with the distributor, included 2.67 FTEs, where one manager should be more than sufficient.
- As DERS acknowledged, portfolios without physical or financial hedges, such as the DRT and RRT portfolios, were less complex when compared to the non-regulated products and therefore should require lower staff time and a lower average salary than a more complex one and should be reduced by 25%.

- The customer education and energy management function proposed by DERS was more appropriately a distributor function, not a retail function and should be eliminated.

In view of the foregoing, the Consumer Group recommended the increase in FTE count be no more than 50% of ATCO Gas's FTE count of 11 and no more than 50% of ATCO Electric's FTE count of 2.5.

The Consumer Group disagreed that the total compensation package proposed by DERS was well within the market range for comparable positions and was supported by both Towers Perrin and Mercer, noting that DERS declined to provide the particular studies to support its position. The Consumer Group stated that as the Towers Perrin and Mercer studies were untested in this proceeding, they could not be given any weight. The Consumer Group also noted that there was no tested data on market ranges for any positions or data on comparable positions.

The Consumer Group submitted that the fully burdened 2004 salary of $155,000 proposed by DERS was grossly above the AltaLink burdened salary levels of approximately $80,000. The Consumer Group submitted the average fully burdened, annual compensation levels should be no higher than $100,000 per FTE.

The Consumer Group was also concerned with the level of embedded bonuses at 26.75%, that resulted in a bonus pool of upwards of $1 million. The Consumer Group noted the amount would be included in revenue requirement whether or not bonuses were paid. Further, the Consumer Group submitted that the incentives for these bonuses were not aligned with reducing customer costs but were based mainly on attaining profitability objectives.

The Consumer Group noted that DERS's proposed management structure was an inverted pyramid structure compared to traditional organizations and argued that the structure better supported the requirements of a non-regulated structure and would not be required if there were separate regulated and non-regulated corporate structures. The Consumer Group submitted the total salary costs in the revenue requirement should not be driven by an organizational structure disproportionately management heavy in relation to other normal utility structures.

The Consumer Group was concerned that the salary costs embedded in developing the Application were in excess of Board guidelines. As DERS was proposing to recover these costs from customers, the Consumer Group considered amounts in excess of the Board guidelines should be to the account of shareholders, not customers.

With respect to corporate costs, the Consumer Group noted that allocated salaries were at a level of $188,000 per FTE and that DERS refused to provide details on the bonus percentage on the basis of confidentiality. The Consumer Group submitted non-disclosure was not appropriate for a regulated business unit seeking recovery of fully burdened salaries in the revenue requirement, as the amounts in question could not be tested. Based on the excessive fully burdened corporate salary level and DERS's reluctance to provide any further disclosure, the Consumer Group submitted a fully burdened average salary level for corporate staff should have no more than a 50% increment over the fully burdened average salary level for Alberta FTEs of $100,000, suggesting a maximum of $150,000 per FTE.

### Views of DERS

DERS stated that the staff salaries for DERS were presented on a fully burdened basis including bonuses and benefits. DERS submitted that the total compensation package was well within the market range for comparable positions and was supported by benchmark information against both regulated and unregulated companies by both Towers Perrin and Mercer studies. DERS argued that the $148,000 average salary for 2003 was in line with the current market and was required to attract and retain a skilled work force for the regulated business start-up and ongoing operations.

DERS submitted that if there was disallowance of any portion of the compensation, the regulated customers would be relieved of paying the prudent costs of a competitively compensated work force required for the provision of regulated services and this would result in a cross-subsidization of customers by its shareholder.

DERS noted that considerable effort was expended by interveners to compare its average fully burdened staff costs to ATCO Gas and ATCO Electric labour cost schedules, which appeared to be unburdened salary costs. DERS submitted that such a comparison was meaningless. In addition, DERS stated that there was a difference in the mix of employees, and no direct correlation between functional duties and responsibilities.

DERS disagreed with the assertions of Calgary and AUMA/CE that DERS's compensation per FTE was excessive and out of line with industry standards. DERS submitted that the record on this issue was extensive. DERS maintained that it needed to attract skilled employees for the regulated business, which will have revenues of $1 to $2 billion. DERS noted that EPCOR recently experienced significant financial losses and customer dissatisfaction related to retail settlement.

DERS disagreed with the Consumer Group suggestions that DERS's FTE requirements were overstated. DERS considered that it erroneously and inappropriately attempted to compare ATCO Gas's requirement of 11 FTEs related to the procurement function to DERS's total DRT requirement of 21.04 FTEs. DERS submitted that the process used by it resulted in a much more valid forecast of FTE requirements than the Consumer Group's suggestion to base FTE requirements on dissimilar ATCO Gas and ATCO Electric functions.

DERS also disagreed with the Consumer Group suggestion that DERS's bonus incentives were not aligned with reducing customers' costs, were related to shareholder benefits, and should be to the account of the shareholder. DERS noted that incentives related to personal objectives included in bonus determinations were for the benefit of the regulated customers, and economic profit included cost management which was again beneficial to the regulated customer.

DERS further disagreed with the Consumer Group's suggestion that DERS proposed an "inverted pyramid" organizational structure that was disproportionate in its weighting to management positions. DERS submitted that if the customer care staff supporting the I-Tek MS Agreement, who act as contractors to DERS, were included in the staff count, the organization would resemble a traditional pyramid structure. DERS noted that, unlike a traditional utility, it had no operational, construction, or field staff.

DERS disagreed with the Consumer Group and AUMA/CE that there was insufficient cost information provided for corporate salaries and bonuses. DERS argued that the level of disclosure provided on the record was appropriate and justified the inclusion of the requested corporate costs in revenue requirements.

### Views of the Board

With respect to the number of FTEs forecast by DERS, the Board notes the suggestions of interveners that in some cases there should be a larger portion of time allocated to non-regulated activities. However, the Board recognizes the importance of ensuring a seamless transition for customers and the Board considers that it would be appropriate for DERS's staff to be focused on the retail transition in 2004. Therefore, the Board will accept DERS's forecast of the number of FTEs for the DRT and RRT.

The Board expects DERS, with the benefit of actual operating experience, to be in a position to provide better justification of the allocation of staff to regulated and non-regulated activities at the time of its next application.

With respect to the average level of employee compensation, the Board agrees with DERS that it is appropriate to compare total compensation to market and that it could be misleading to focus on one element of compensation such as bonuses.

The Board considers that bonuses, if appropriately structured, can be an appropriate component of an overall employee compensation package even in a utility or non-profit situation.

The Board also agrees with DERS that it would be unfair to compare its average salary, which excludes staff providing the customer care function that has been outsourced to ATCO I-Tek, to the average salary of a utility which includes operational or field staff. The Board also agrees that it is not appropriate to compare fully burdened salaries with salaries that are not fully burdened. Nevertheless, the Board is not persuaded that it is reasonable for DERS's average compensation level to be as far above the average compensation level of ATCO and AltaLink as it appears to be.

Furthermore, the Board agrees with interveners that DERS has not provided sufficient justification to satisfy the Board that its forecast average compensation levels are market competitive. The Board notes with concern that DERS did not provide the market studies upon which it professed to rely.

Therefore, for the purposes of this Decision, the Board will reduce DERS's forecast average compensation levels by 10% for the DRT and RRT.

The Board expects DERS to justify that its compensation levels are in line with the market at the time of its next application.

While the Board will not direct DERS to use time sheets or to undertake time and motion studies at this time, the Board expects DERS, with the benefit of actual operating experience, to provide a more comprehensive justification of the allocation of labour costs between the DRT, RRT and non-regulated functions at the time of its next application.

### Customer Education and Energy Awareness

DERS's total budget for customer education and energy awareness was split between the RRT and DRT based on the number of respective customer months. The breakdown of the forecast costs is shown in Table 16.

**Table 16. Customer Education and Energy Awareness Costs**

| | (000's) | | | |
|---|---|---|---|---|
| **Budget Area** | **5 Months** | | **12 Months** | |
| | **Electricity** | **Gas** | **Electricity** | **Gas** |
| Deregulation and Consumer Choice Education | 141 | 709 | 378 | 1,897 |
| Energy Efficiency Education | 20 | 105 | 75 | 375 |
| Education – Bill Format, Phone Numbers | 17 | 83 | | |
| Website Design | 33 | 167 | 17 | 83 |
| Customer Research | | | 29 | 146 |
| Community Relations | 17 | 83 | 50 | 250 |
| **Total RRT and DRT** | **227** | **1,148** | **546** | **2,754** |
| **TOTAL** | 1,375 | | 3,300 | |

DERS indicated that its customer education and energy awareness program would provide information regarding industry structure, deregulation and on choices customers have. DERS proposed that it would use television, radio and print campaigns as well as bill inserts. DERS indicated that it would provide conspicuous references to the government website, www.customerchoice.gov.ab.ca, where a full list of all licensed retailers could be obtained.

DERS proposed to provide energy efficiency tips, explanations on why the bill format had changed, changes to key phones numbers and reassurance of continuing energy supply.

DERS indicated that it would conduct customer research to determine the effectiveness of its education and energy awareness information and customer satisfaction with service levels. DERS noted that any customer surveys conducted would be concurrently made public to all parties by way of publication on DERS's website.[104]

DERS also proposed to sponsor various events in the community in order to give DERS a presence in the community, so that consumers had awareness and confidence in them.

### Views of the Interveners

### Calgary

Calgary submitted that the request of DERS for $1.4 million in 2003 and $3.3 million in 2004 was extremely excessive.

Calgary submitted that the primary responsibility for customer education regarding deregulation and restructuring should be with the Government. Calgary noted that in Manitoba all stakeholders participated in a proceeding where the content of the customer education information was determined under a "Generic Consumer Education/Information Package. Calgary indicated that information was then approved by the Manitoba PUB before it was provided to customers.

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[104] Tr. pp. 863-866

Calgary stated that since DERS had a number of business interests, it would be difficult for it to provide customer information that would not be considered by some to have a corporate purposes as well as customer education. Calgary submitted that anything that had its lightning bolt logo could be considered as enhancing its corporate position in addition to whatever customer information was provided.

Calgary submitted that given that DEML's unregulated entities stand potentially to benefit from such information, an incentive exists for DEML to include information that would be beneficial to those entities.

Calgary submitted that there should be a minimal role for DERS in providing customer information and that any information over and above what was provided by the Government should be provided by the ATCO utilities.

Calgary submitted that the only information that DERS should provide was two bill stuffers indicating that DERS was now providing the service as default supplier (gas) and regulated rate supplier (electricity) and based upon information in the proceeding, the cost of two bill inserts would be between $100,000 and $200,000.

Calgary submitted that DERS's website should be limited to information needed by default or regulated supply customers and that sources of independent information on other items could be provided via links. Based upon information in the proceeding, Calgary submitted that $200,000 in 2003 and $100,000 in 2004 might be required for web design and maintenance, however, Calgary stated that the record showed that ATCO I-Tek was also providing some of those services.

Calgary submitted that items such as community sponsorship which were included in the communication cost forecast were related to enhancing the brand name of DEML and its lightening bolt logo. Calgary argued that given the various commercial activities of DEML it was unlikely that any "education" would be totally neutral.

Given all the other sources of customer education and energy awareness including the government expenditures, Calgary suggested that a modest amount should be included in the revenue requirement for DERS and for the five-month period, the amount should not exceed $500,000 and for the twelve-month period the amount should be reduced by $2.3 million, since the need for customer education would have decreased.

### Consumer Group

The Consumer Group was concerned with the tremendous expenditures being proposed by utilities such as ATCO and DERS in the area of "customer education and awareness." The Consumer Group stated that customers were repeatedly being made to pay for information on the effects of deregulation from the Board, utilities, non-regulated suppliers and the Government. The Consumer Group argued that there was no oversight of the overall campaign by these sources and, for the most part, it would appear the underlying theme of informing customers about customer choice was the same. The Consumer Group submitted that for customers with no interest in moving to non-regulated suppliers, the expenditure was of absolutely no value.

The Consumer Group submitted that the development of customer choice had little to do with regulated utility service and that advertising, customer awareness and education on deregulation and customer choice should properly be the responsibility of the non-regulated supplier.

The Consumer Group saw some benefit to customers from bill stuffers and information on matters such as why the bill format changed and changed telephone numbers. However, the Consumer Group submitted that it was not, nor had it ever been, the appropriate function of a regulated utility to try and explain government policy or the impacts of that policy to its customers. The Consumer Group argued that customers should not be required to pay for marketing type information benefiting Direct Energy and its brand name.

Initially, the Consumer Group recommended that the $4.6 million forecast for customer education should be reduced to no more than $1 million for the 2004 period, but later argued that expenditures should be limited to the amount required to provide information concerning changes in telephone numbers and billing format. The Consumer Group submitted that if the Board approved any additional amounts, DERS should be directed to include the following clause as part of any media message, bill insert, ad, etc.:

> This message is produced by Direct Energy Regulatory Services at the expense of, or is otherwise paid for by, those customers receiving the Regulated Rate Tariff or the Default Rate Tariff. The opinions expressed are those of Direct Energy. They are not intended to reflect, or be representative of, any view or opinion of any consumer or customer group.

The Consumer Group submitted that DERS should not supplant the government's own public awareness program just because the government commented that consumers required more information related to the energy market, but that only 56% felt that the government was the best source for that information.

The Consumer Group also submitted that DERS did not provide any evidence to support its claim that a "mass-market media approach" was more cost-effective and consistent than providing information through the call centers. With respect to DERS's comparison of the low cost of a bill insert compared to a 350-second call to the call centre, the Consumer Group submitted that such calls would only be applicable to a very small percentage of customers, whereas the bill insert would apply to all customers, regardless of their current level of understanding or interest in receiving such information.

The Consumer Group submitted that DERS's intention to provide "conspicuous references to the government website, www.customerchoice.gov.ab.ca, could easily be printed on the bill or included with a bill insert from time to time and argued that an extensive media campaign was not required.

The Consumer Group submitted that a regulated utility proposing to spend such a large amount on customer education should have its material scanned and approved by the Regulatory Authority before any material sum was included in the approved revenue requirement. In this regard, Consumer Group noted that DERS indicated that its compliance plan would address the issue of approval of customer education and awareness materials prior to distributing these materials to its customers or publicly. However, Consumer Group argued that it was not reasonable to collect $4.6 million from customers only to cut back on the program before it was implemented.

### HVAC

HVAC submitted that one of the clear and undisputed intentions of the customer education program was that the broad Alberta market place would become familiar with the DEML brands including the brand of DEP. HVAC argued that familiarization with those brands was a benefit clearly associated with DEML's strategy and financial incentive to migrate and cross-sell DERS customers.

HVAC submitted that there was insufficient evidence to support the significant costs DERS was intending to incur for the purposes of its "customer education" program, where the intent or the effect was to provide the general public with an understanding or favourable impression of who DEML was pursuant to its business strategy. HVAC argued that it was not an activity or cost which should be allowed to be recovered through rates charged to DERS customers.

HVAC also submitted that effective oversight was warranted with respect to the content of the specific information programs. HVAC argued that this important matter should not be relegated to a Code of Conduct matter, such that the acceptability of specific content was left to the initial judgment of DERS with the only recourse for customers or other market participants to be the after the fact complaint process. HVAC submitted that oversight in that manner would not be commensurate with the significance of the competitive concerns at play. HVAC stated that it was important to get it right, to avoid disputes after the fact regarding acceptable content and prudent costs.

HVAC stated that there may be certain types of customer focused information which DERS (or ATCO), as a regulated service provider, may be well positioned to provide in the overall public interest. HVAC noted one example could be assistance with respect to sources of information on energy efficiency provided that it was presented in a manner that did not create a preferential benefit for DEML.

HVAC stated that should the Board find that certain types of information for the purposes of educating customers was best provided by regulated entities including DERS, then the Board should consider whether benefits from such programs accrue to other affiliates of DERS that similarly carry on business under a "Direct Energy" banner and logo.

HVAC noted that section 22 of the *Gas Code Regulation* obligated an allocation of economic benefit or cost as between a DSP and its affiliated retailer when costs or expenses were incurred in respect of research and development. HVAC submitted that research and development in these circumstances might be properly interpreted to include customer awareness, "customer education" and advertising for market development purposes.

### Views of DERS

DERS submitted that its customer education and energy awareness program would respond to consumers' requirements for information regarding industry structure, deregulation and changes to their bill format and service provider. As the new face to the consumer through the billing relationship, DERS submitted that it was required to provide assurance and education.

DERS submitted that given the cost structure of the I-Tek MS Agreement, a strong customer education program would have direct benefits relating to the efficient use of the call centre resources. DERS also submitted that the program was a cost-effective alternative to providing wide spread customer education on a customer-by-customer basis. DERS argued that ad hoc and individual responses did not provide the consistency and quality of a mass-market media approach.

DERS noted that the provincial government recently issued an RFP inviting parties to submit proposals for a consumer protection and customer choice campaign. The government stated that their survey results showed that 92 percent of respondents required more information related to the energy market, but only 56 percent felt that the government was the best source for that information. DERS argued that this clearly demonstrated that customers required and demanded more information and educational materials than they were currently receiving and DERS submitted that that this information and education must be provided by other market participants in addition to the government.

DERS submitted that its customer education program would be neutral, factual, and unbiased and that information concerning the new market structure and the enhanced choices available to consumers would benefit all consumers including those who chose to remain on regulated service.

DERS also noted that energy awareness information would also be a major component of the program and DERS submitted that this information was identified in consumer research as being of key importance to consumers.

DERS stated that it has a significant responsibility in assuming the role of the regulated service provider. DERS submitted that Alberta consumers would experience changes in their relationship with their regulated providers, coupled with significant structural changes in the industry itself and DERS argued that it would become the direct interface between customers and the Alberta energy market.

DERS submitted that it was clear that DERS would in no way provide benefits to its unregulated affiliates through this process, but would simply be providing a needed and expected role to consumers. DERS indicated that its compliance plan would address the issue of approval of customer education and awareness materials prior to DERS distributing these materials to its customers or publicly.

DERS submitted that in the ATCO Gas 2003/2004 GRA, the Consumer Group argued that costs should be removed from ATCO Gas's revenue requirement, as DERS would be best suited to provide the required customer education and energy awareness information and should therefore include the costs in its revenue requirement. DERS also submitted that the Consumer Group was now arguing in this proceeding that the distributor should perform that function and DERS should not include those costs in its revenue requirement. DERS argued that the Consumer Group's positions were inconsistent and should be disregarded.

**Views of the Board**

The Board notes that both Calgary and the Consumer Group submitted that there should be a minimal role for DERS in providing information to customers on industry restructuring. However, the Board considers that it is reasonable for RRPs to play some role in providing customer education of this nature, particularly given their control of the billing envelope.

Therefore, the Board will approve the amounts requested by DERS for deregulation and customer choice education for the proposed print campaign and for the proposed bill inserts. However, the Board does not agree with DERS that it is necessary or appropriate for RRPs to engage in television or radio campaigns with respect to this matter. The Board will not include the amounts proposed in respect of the television and radio campaigns in the allowed revenue requirement.

The Board is satisfied and will approve the amounts requested by DERS for energy efficiency education, education on changes in bill and phone numbers, website design and customer research. The Board notes that education regarding changes in bill and phone numbers were one-time costs included in the five-month test period. The Board will therefore add these costs to the approved 2004 revenue requirement. Similarly, the Board notes there were some one-time website design costs included in the five-month test period; the Board will also add these costs to the approved 2004 revenue requirement.

The Board is not persuaded, however, that it is appropriate to include community relation sponsorships in the allowed revenue requirement. The Board considers that such sponsorships are not necessary or appropriate for the provision of DRT and RRT services.

In summary, the Board will approve the following amounts for customer education and energy awareness for the DRT and RRT:

**Table 17. Customer Education and Energy Awareness Costs – Board Approved**

| | (000's) | | | |
|---|---|---|---|---|
| Budget Area | 5 Months | | 12 Months | |
| | Electricity | Gas | Electricity | Gas |
| Deregulation and Consumer Choice Education | | | 118 | 592 |
| Energy Efficiency Education | | | 75 | 375 |
| Education – Bill Format, Phone Numbers | | | 17 | 83 |
| Website Design | | | 50 | 250 |
| Customer Research | | | 29 | 146 |
| Community Relations | | | 0 | 0 |
| **Total RRT and DRT** | | | **289** | **1,446** |
| **TOTAL** | | | 1,735 | |

### Information Systems

DERS's forecast of information systems costs for the RRT and DRT are set out in Tables 7 and 11 respectively. The Board considers DERS's forecast of information systems costs to be reasonable and accepts the forecasts as filed for the purposes of determining the approved revenue requirements for the DRT and RRT. The Board notes that no intervener commented on information systems costs.

### Other Administration Costs

DERS's forecast of other administration costs for the RRT and DRT are set out in Tables 7 and 11 respectively. The Board considers DERS's forecast of other administration costs to be reasonable and accepts the forecasts as filed for the purposes of determining the approved revenue requirements for the DRT and RRT. The Board notes that no intervener commented on other administration costs.

### Interest on Security Deposits

DERS's forecast of interest on security deposits for the RRT and DRT are set out in Tables 7 and 11 respectively. The Board will address the appropriate rate of interest to be paid on security deposits in section 5, Terms and Conditions. The Board considers DERS's forecast of interest on security deposits to be reasonable and accepts the forecasts as filed for the purposes of determining the approved revenue requirements for the DRT and RRT.

### Corporate Costs

DERS's forecast of corporate costs for the RRT and DRT are set out in Tables 7 and 11 respectively.

### Views of the Interveners

Comments from interveners with respect to the labour portion of corporate costs are included in section 4.1.1.6. Interveners did not comment on the non-labour portion of the corporate costs.

### Views of DERS

DERS submitted that the corporate costs were linked to the governance role provided by DEML and argued that this strong governance, combined with a robust reporting structure, would ensure that the regulated business has a strong control environment and oversight.

DERS submitted that strong corporate support was required for the regulated business, given the volume of transactions and the dollar value of the transactions associated with the purchase of energy for and the revenue collection from regulated customers. DERS believed it could provide those functions for customers on a more cost effective basis through sharing of corporate resources than on a stand-alone basis, and that the allocation of these costs to DERS was appropriate and fair.

### Views of the Board

The Board notes that labour costs represent approximately 40% of the total corporate costs, and further notes the concerns expressed by interveners regarding the average level of compensation related to the corporate costs. The Board notes that the average level of compensation related to the corporate costs is approximately $188,000.

The Board has concerns with respect to the labour component of corporate costs similar to the concerns expressed regarding staff salaries above. Therefore, for the purposes of this Decision, the Board will reduce the labour portion of the total corporate costs by 10% for the DRT and RRT. Since labour costs represent approximately 40% of the total corporate costs, the resulting reduction to the total corporate costs will be 4%.

The Board expects DERS to further justify the amount of its corporate costs at the time of its next application.

### 4.1.1.7 Bad Debt Expense

DERS's forecast of bad debt expense for the RRT and DRT are set out in Tables 7 and 11 respectively. The Board considers DERS's forecast of bad debt costs to be reasonable and accepts the forecasts as filed for the purposes of determining the approved revenue requirements for the DRT and RRT. The Board notes that no intervener commented on DERS's forecast of bad debt expense.

#### 4.1.1.8 Penalty Review

DERS's forecast of penalty revenue for the RRT and DRT are set out in Tables 7 and 11 respectively. The Board notes that no intervener commented on DERS's forecast of penalty revenue. The Board also notes DERS's position that assessing penalty revenue at 1.5% per month on the outstanding balance rather than on the basis of a one-time 5% late payment penalty would have no effect on the forecast of penalty revenue. The Board considers DERS's forecast of penalty revenue to be reasonable and accepts the forecasts as filed for the purposes of determining the approved revenue requirements for the DRT and RRT.

### 4.1.2 Non-Energy Revenue Requirement Allocation and Rate Design

With respect to the DRT and RRT non-energy revenue requirements, DERS allocated the various cost categories to the rate classes using the allocation methods shown in Table 18. Table 18 also shows whether the costs in each category would be recovered as part of a Customer Charge or as part of a Variable Charge.[105]

**Table 18. DRT and RRT Cost Allocation and Recovery Methodology**

| Cost Category | Allocation Basis | Recovery Basis |
|---|---|---|
| Customer Care | Bills | Customer Charge |
| Bad Debt | Bills | Customer Charge |
| Penalty Revenue | Bills | Customer Charge |
| Credit Charges | Bills | Customer Charge |
| Customer Education | Customers | Customer Charge |
| Salaries | Customers | Customer Charge |
| Corporate Costs | Customers | Customer Charge |
| Information Systems | Customers | Customer Charge |
| Other Administration Costs | Customers | Customer Charge |
| Interest on Security Deposits | Customers | Customer Charge |
| Amortization of Hearing Costs | Customers | Customer Charge |
| Amortization of Integration Costs | Customers | Customer Charge |
| Working Capital | Energy Consumption | Variable Charge |

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[105] For each test period, the Customer Charge for each rate class was derived by taking the fixed costs allocated to the respective rate class and dividing by the number of customer months for the respective rate class. For each test period, the Variable Charge for each rate class was derived by taking the variable costs allocated to the respective rate class and dividing by the Sales for the respective rate class.

### Views of the Interveners

#### Calgary

Calgary submitted that the proposed rate design for DRT Rate 1 was unduly burdensome on residential customers and argued that the range of disparity within a given rate schedule rewards the larger customers at the expense of the smaller customers served under the schedule. Calgary submitted that small customers should not be burdened in this manner and argued that rather than a fixed rate, the Board should consider the implementation of a commodity rate or a uniform split between customer and commodity charges to help level the impacts on ratepayers within a given rate class.

#### CCA

The CCA submitted that the use of bills and customers to allocate costs results in more costs being allocated to residential customers.

The CCA submitted that DERS was attempting to increase the residential rate in order to meet non-regulated marketing requirements, by increasing available margin or headroom. The CCA also argued that DERS wished to minimize its risk by moving cost allocations from energy to customers, since energy based rates are more risky because energy consumption varies more than the number of customers.

The CCA noted that using a cost allocation designed for electrical rates may not be appropriate for natural gas rates. The CCA noted that residential, commercial and industrial customers were included in the same rate class for natural gas, but have separate rate classes for electricity.

The CCA submitted that cost allocations should not be done on the basis of bills because bill consolidation does little to reduce costs.

The CCA submitted that bad debt costs should be allocated based on energy as opposed to bills because bad debt levels are driven by energy purchases.

CCA recommended that credit charges be allocated based on energy rather than on the basis of bills because credit charges are expended to reduce bad debt costs.

The CCA submitted that customer education and energy awareness costs should be allocated on the basis of energy because energy efficiency improvements are directly related to energy consumption.

The CCA submitted that costs associated with energy procurement and portfolio management, finance and retail settlement, credit and associated accounting functions should be classified to commodity and than allocated by energy. The CCA also submitted that regulatory, senior management, communications, information systems, other administration and corporate costs should be assigned to both customer and commodity.

The CCA submitted that since security deposits provide a direct offset to net working capital, the costs of security deposits should be allocated by energy, the same allocation as net working capital.

The CCA submitted that hearing costs should be allocated based on an assignment of 50% of the costs to customers and 50% to energy to ensure larger customers pick up a fair share of their costs.

The CCA submitted that the Board must apply usual rate design principles in the design of DERS rates and that the effects of rate shock must be taken into account. The CCA argued that the proposed residential rate increases must be tempered and an effective way to temper the residential rate increase was to minimize the increase in the fixed component of the rate and increase the variable charge.

The CCA submitted that a maximum of 60% of the customer care costs should be recovered in the fixed rate component with the remainder in the variable rate component. The CCA argued that higher energy charges and lower fixed charges encourage conservation and was therefore in the public interest.

### PICA

PICA submitted that the proposed classification and allocation of costs adequately reflected cost causation and argued that any attempt to classify more of the fixed non-energy costs as energy would result in misallocation of costs between large and small customers. PICA stated that the result would be a cross subsidy by larger customers to smaller customers.

PICA submitted that energy related bad debts and penalty revenues should be classified and allocated on the basis of energy, while non-energy related bad debts and penalty revenue should be classified and allocated on the basis of number of bills. PICA argued that this was a close approximation to the non-energy revenue by class.

PICA submitted that the allocation of credit charges should follow the same method used for customer care services since credit charges relate to the provision of customer care services by ATCO I-Tek.

PICA submitted that customer education and awareness costs should be allocated on the basis of number of customers. PICA argued that potential savings from energy conservation was not relevant to cost causation. PICA submitted that the effort, time and cost involved in delivering the message of conservation was related to cost causation and PICA argued that this effort was the same regardless of whether a customer was residential or commercial.

PICA submitted that salaries for finance and retail settlement as well as credit and associated functions should not be allocated based on energy because none of these costs were related to level of energy consumption.

PICA submitted there was no relationship between the market price of energy and hearing costs and that the components of revenue requirement classified as energy do not justify a 50/50 classification of hearing costs to energy and customers.

### Views of DERS

DERS proposed to maintain the existing rate classes for RRT and DRT service due to differences in the utilization of billing consolidation by the various rate classes, as well as differences in load profiles for each of the rate classes.

DERS submitted that its forecast non-energy revenue requirements for the test periods were allocated to various rate classes following the methodology approved by the Board in Decision 2002-85 for ATCO Electric and that this methodology was the most appropriate for a retail entity.

DERS submitted that components of the revenue requirement were allocated to the rate classes on either the number of bills, the number of customers, or on energy consumption, based on causative factors.

DERS characterized those costs related to the number of bills or the number of customers as fixed costs and characterized those costs related to energy consumption as variable costs.

DERS submitted that a significant portion of the total customer care cost was related to the number of customers after billing consolidation and that bad debt costs and penalty revenue were expected to strongly correlate to the number of customers after billing consolidation. Therefore, DERS argued that allocation of customer care costs, credit charges, bad debt cost and penalty revenue to the various rate classes should be based on the number of customers after billing consolidation.

DERS noted that there was currently no utilization of billing consolidation by DRT customers and none forecast during the test periods. Therefore, the number of bills was equal to the number of customers for the DRT.

DERS submitted that the primary driver for customer education and energy awareness, staff salaries, corporate costs, information system costs, other administration costs, interest on security deposits, amortization of hearing costs, and amortization of integration costs was the number of customers. Therefore, DERS argued that the allocation of these costs followed cost causation and was based on the number of customers in each rate class.

DERS stated that a significant portion of the working capital required by DERS was driven by the Distribution Tariff, franchise fees and the payment equalization plan, and DERS argued that these items were all closely related to energy consumption. Therefore, DERS submitted that the allocation of these costs followed cost causation and was based on the forecast consumption for each rate class.

DERS submitted that the proposed rates were based on the principle of allocating the proper costs to the various rate classes and recovering those costs from the rate classes in a manner reflecting that allocation.

DERS submitted that the misallocation of an arbitrary proportion of fixed costs to the variable component of rates would violate underlying cost causation and would be preferential to smaller users while discriminating against larger users.

**Views of the Board**

The Board notes that no party proposed any changes to the existing definitions of rate classes for the RRT and DRT. The Board considers that it is appropriate to maintain the existing definitions of rate classes.

With respect to the allocation of the non-energy revenue requirements to the rate classes, Board notes CCA's submission that it would be more appropriate to use the number of customers rather than the number of bills as the allocator for certain cost categories. The Board notes that DERS's use of the number of bills is consistent with the approach used for the RRT (then RRO) in Decision 2002-085. For the DRT, the Board notes that that the number of customers and the number of bills are forecast to be the same during the test period, and therefore the use of the number of customers instead of the number of bills as an allocator would have no impact on the resulting rates. The Board considers DERS's use of the number of bills as an allocator for certain cost categories to be reasonable.

The Board also notes CCA's submission that it would be more appropriate to allocate certain cost categories to rate classes on the basis of energy rather than customers or bills.

With respect to the RRT, the Board notes that DERS's allocation method for the RRT is consistent with Decision 2002-085. The Board considers that there is merit in maintaining the same methodology for allocation of RRT costs at this time.

With respect to the DRT, the Board notes that DERS has allocated all procurement and portfolio management costs, and the commodity-related portion of credit charges, working capital, bad debt and penalty revenue, to the DRT energy revenue requirement. For example, the Board notes that 71% of the total bad debt and penalty revenue was allocated to the DRT energy revenue requirement. The Board therefore considers that it would not be appropriate to recover the remaining portion of credit charges, bad debt and penalty revenue, which have been allocated to the non-energy revenue requirement, on the basis of energy consumption.

The Board does consider that there may be merit in allocating interest on security deposits in the same manner as the allocation of working capital, since security deposits are used as an offset to working capital. The Board also considers that there may be some merit in allocating a portion of hearing costs, regulatory, senior management, communications, information systems, other administration and corporate costs on the basis of energy consumption. However, the Board recognizes that these costs represent a small portion of the total revenue requirement, and furthermore the portion of these costs that might be more appropriately allocated on the basis of energy consumption could also be small. Therefore, the Board expects that such a refinement to the allocation method would not have a material impact on the resulting DRT and RRT rates.

Nevertheless, the Board directs DERS to investigate the merits of these possible refinements of the allocation method at the time of its next DRT and RRT applications.

The Board considers that DERS's allocation methods appropriately reflect cost causation. The Board notes CCA's submission that the Board should also consider other criteria such as rate shock in the establishment of the final rates.

The Board acknowledges that costs to consumers will increase as a result of the separation of the distribution and regulated retail functions. The Board notes that the potential for increased costs as a result of this separation was explicitly contemplated in the legislation, and the Board is required by the legislation to allow the recovery of reasonable increased costs from customers.

The Board notes that the rates approved in this decision will be offset to some extent by reductions in gas distribution rates. The reduction in the level of gas distribution rates will be addressed in subsequent Board decisions.

The Board notes that the increased costs due to the separation of the distribution and regulated retail functions affect all customers, and not just certain rate classes. To mitigate the impact of the increase for one rate class would require an even greater increase for other rate classes.

The Board also does not consider that the net impact of the separation of the distribution and regulated retail functions is of sufficient magnitude to warrant phasing in the impact over more than one test period.

Considering all of the above, the Board will accept DERS's proposed DRT and RRT allocation methods and rate design for the purposes of this proceeding.

## 4.2 Gas Cost Flow-Through and Energy Revenue Requirements

### 4.2.1 Energy Procurement and Price Setting Model

DERS proposed to charge DRT customers using the flow-through rate prescribed by section 3(5) of the *DGS Regulation*. DERS also proposed to utilize the methodology used by ATCO Gas concerning the energy procurement and pricing model, the determination of energy rates and management of the DGA.

DERS indicated that it would follow the general protocols for gas procurement as contained in Decision 2001-75 and that its purchasing practices would generally align with current ATCO Gas practices for gas procurement. DERS indicated that it would continue to have North and South gas supply portfolios, but it would seek approval from the Board to migrate the North and South portfolios to a single GCFR and DGA once the transitional issue of Salt Cavern Storage inventory on the ATCO Gas North system was addressed. DERS noted that it did not intend to use storage in the South portfolio.

DERS stated that it would arrange for base load supply on a monthly index basis and would acquire additional daily requirements on either a daily index basis or under fixed price arrangements. DERS also noted that it was currently evaluating the reasonableness of increasing the amount of base load supply contracted on a monthly index basis and that it intended to present any proposed change to stakeholders prior to any proposed implementation through GCFR filings.

DERS noted that it intended to actively pursue the acquisition of gas supplies on the ATCO Pipelines system and that any price advantage captured in the purchase of these supplies would flow to regulated customers. DERS indicated that it would enter into structured peaking arrangements whereby DERS would have access to secure supplies, on a daily index basis, from certain major suppliers in order to increase security of supply for regulated customers and reduce administration effort and dependence on the NGX.

DERS indicated that it would take assignment of certain supply contracts from ATCO Gas as listed in the GATA.[106] Exhibit 005-39 provided an update of the status of these contracts.

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[106] Filed in the Retail Sale Application

> The Gas Assets Transfer Agreement ("GATA") contemplates that Direct Energy Marketing Limited ("DEML") would assume all the Major Contracts (as that term is defined in the GATA), which contracts relate to ATCO's Gas regulated customer gas supply. DEML and ATCO Gas have jointly identified and assessed a total of 131 Major Contracts.
>
> Eleven contracts related to certain EUB approved sales of ATCO Gas company-owned production, and were previously assigned with those properties.
>
> No production was flowing from 53 contracts, which were or will be cancelled by ATCO Gas or expired by the deal close, and therefore could not be assigned to DEML.
>
> The balance of the contracts will either be assigned to DEML at Closing or, as contemplated by paragraph 13.3 in the GATA, if there is not an effective assignment in place as of Closing, ATCO Gas and DEML will enter into commercially reasonable arrangements to provide a resale by ATCO Gas to DEML of the volumes of gas to be supplied under such contracts with no increase in price. Therefore, the costs and benefits of the balance of the Major Contracts will continue to flow to regulated customers through the GCFR.
>
> DEML and ATCO Gas will continue to assess the supply contracts throughout the period leading to Closing. The contract counts listed previously constitute the most current accounting but are subject to change as additional information is collected. Direct Energy Regulated Services' customers will continue to receive the benefits and costs of all active Major Contracts, regardless of whether they are assigned to DEML or remain with ATCO Gas.

DERS indicated that it would be utilizing the Energy Management Group's Gas Supply personnel within DEML to provide the gas purchasing and gas portfolio management function. DERS also indicated that this group purchased supply for all of DEML's North American operations.

With respect to protocols for procuring gas for its regulated and unregulated businesses, DERS noted that all procurement activities for the regulated business would be tracked and accounted for separately, using the appropriate risk, nomination and accounting systems. DERS also noted that it would use the following protocol:

- Any gas purchases longer than one day will be ticketed, at the time of the transaction, to either the regulated or unregulated portfolio.
    - Index purchases will be time stamped, with the bid and ask prices at the time recorded and benchmarked against the index marks reported at the end of the business day.
- Short-term purchases[107] will be pooled and allocated to the regulated and unregulated portfolios on a pro rata basis based on the demand numbers for the respective pools.
    - Transactions will be time stamped, with the bid and ask prices at the time recorded, and benchmarked against the index marks reported at the end of the business day.

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[107] DERS defined short term purchases as transactions up to and including one day

With respect to GCFR filings, DERS indicated that consistent with ATCO Gas, DERS would file information packages with the Board on the fifth last business day of each month and that the information package would be structured in the manner currently provided by ATCO Gas in its monthly GCRR filing. DERS indicated that it would file all schedules required to provide the appropriate level of detail respecting the DGA balances and to support the GCFR calculations.[108] Section 4.3.2 (Deferral Accounts) discusses the filing process associated with non-energy deferral accounts.

### Views of the Interveners

### Calgary

Calgary submitted that DERS was providing a new and untested natural gas supply procurement and pricing model and that DERS did not articulate its gas supply acquisition strategy or plan to supply the commodity needs of the default gas supply customers.[109] Calgary argued that prior to any Board approval, DERS should file a gas supply plan.

Calgary submitted that DERS was changing its gas supply and management strategies from that of ATCO Gas, in that numerous supply contracts would not be assigned[110] and that DERS proposed to change the mix of daily and monthly purchases.[111]

With respect to assignable gas contracts, Calgary noted that DERS was still assessing the contracts and argued that the DERS criteria for rejecting assignable contracts was not clearly stated, nor were the costs and benefits indicated. In addition, Calgary argued that it was not clear how customers would benefit if the contracts were retained by ATCO.

Calgary also submitted that DERS proposed to become obligated to balance both ATCO Pipelines and ATCO Gas and argued that this would cause core customers to bear this cost burden.

With respect to gas purchasing activities, Calgary submitted that there would be no practical process or procedure to review and evaluate the purchase decision-making process, the portfolio management process, or the gas management strategy of the unregulated entity. Calgary argued that unless full and open accountability of procurement group was provided, the opportunity for cross-subsidization would be rampant.

Calgary submitted that the pooling of the day gas was just another example of DERS's proposals to merge regulated and unregulated activities. Calgary argued that there was no assurance that daily requirements of regulated and unregulated consumers had equivalent daily load profiles let alone hourly profiles. Calgary submitted that the gas portfolios must be tailored to meet the individual hourly and daily load requirements of both the regulated and unregulated markets, and that co-mingling of the portfolios would not meet this objective; nor would it meet the required transparency for review and evaluation of gas purchasing practices.

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[108] BR-DERS-30

[109] See CAL-DERS-19

[110] DERS Undertaking Tr. p. 1029

[111] CAL-DERS-19(g)

Calgary submitted that DERS's business plan was driven by the goal of switching regulated customers to unregulated services including gas supply and argued that there was an inherent conflict of interest in the proposal to have the unregulated affiliate provide both regulated and unregulated gas supply. Calgary argued that the Board must place a condition indicating the gas purchasing activities be fully transparent, or alternatively direct DERS to provide an alternative gas purchasing process.

Calgary submitted that DERS proposed to modify the currently used format for filing its equivalent of the GCRR.[112] Calgary noted that prior to the implementation of the monthly GCRR, the Board directed that ATCO Gas file a mock February 2002 GCRR for review in order to allow parties to review and evaluate the new GCRR.[113] Calgary argued that due to the magnitude of the changes to the GCRR emanating from this proceeding, the Board should follow the mock GCRR procedure and direct DERS to follow a similar process leading up to its first month of being the default gas supplier. DERS submitted all parties would thereby be able to evaluate the gas supply strategy and management practices of DERS.

**Views of DERS**

DERS noted Calgary's suggestion that DERS did not articulate its gas supply plan and that DERS would be advancing a new and untested supply and pricing model. DERS submitted that these assertions were not supported. DERS also submitted that the imposition of a detailed procurement procedure would impose a buying strategy and criteria that may not be possible to adhere to under the weather and operating conditions experienced in Alberta. DERS argued that any rigid procurement strategy may impose unnecessary costs and/or risks on DEML and the regulated customers. DERS stated that DEML's procurement activities would be transparent through the monthly GCFR filings and all purchases will be tracked and auditable.

DERS also noted Calgary's assertion that DERS was changing supply and management strategies based on the fact that certain contracts would not be assigned from ATCO Gas. DERS argued that to suggest that DERS was changing strategies was ludicrous. DERS submitted that it was clear and understandable that third party contracts actually flowing gas would be assigned to DERS, or in the event they were un-assignable, commercial arrangements would be entered into to ensure that regulated customers received the benefits or costs implicit in the pricing and volume arrangements of the contracts.

DERS noted Calgary's suggestion that DERS used some subjective criteria to determine whether or not to take assignment of the gas supply contracts listed in the GATA. DERS argued that it was nonsensical to suggest that DERS should take assignment of contracts that were previously been assigned to others, or that have expired or been terminated.

With respect to quantifying the benefits of the contracts, DERS argued that the exercise would be futile in the absence of knowing future gas prices.

DERS also noted Calgary's suggestion that DERS proposed to modify the mix of daily and monthly index purchases, but argued that it intended to discuss any proposed changes with stakeholders prior to any proposed implementation.

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[112] BR-DERS-30

[113] Decision 2001-075, Directive 7

With respect to Calgary's suggestion that DERS was proposing to become obligated to balance the ATCO Gas and ATCO Pipelines systems, DERS argued that the record was clear that the regulated portfolio was the swing, or balancing, supply on these systems today. DERS suggested that no change was contemplated, or even possible, until the implementation of ATCO Gas's Retailer Service and Load Balancing proposal.

DERS noted Calgary's comment that there was inherent conflict of interest in the proposal to have the unregulated affiliate provide both regulated and unregulated gas supply and that there would be neither transparency nor the ability to review and evaluate the gas purchasing process. DERS submitted that its procurement protocol would provide an acceptable audit trail and would ensure fair treatment for both regulated and unregulated customers.

DERS noted Calgary's assertion that DERS proposed to modify the current GCRR filing format. DERS argued that Calgary misconstrued its proposal whereby DERS proposed to file all schedules required to provide the appropriate level of detail respecting the DGA balances and to support the GCFR calculations.

DERS noted that it did not intend to use storage in the South portfolio and submitted that this would not impact the South GCFR relative to ATCO Gas South's current GCRR, as currently any price impacts, either positive or negative, were flowed to customers through ATCO Gas's Storage Rider.

**Views of the Board**

The Board notes that section 3(5) of the *DGS Regulation* requires that the gas charge must be calculated on a monthly flow-through basis, as determined by the Board. The Board notes that DERS requested approval to use the same pricing model that ATCO Gas currently uses for its monthly GCRRs. The Board does not agree with Calgary's assertion that DERS would be providing a new and untested pricing model. Therefore, the Board approves DERS's proposed GCFR pricing model.

With respect to the reasonableness of DERS's gas supply portfolios, the Board notes that DERS indicated that it will have a mix of monthly index and daily index gas and that it will utilize any assigned contracts from ATCO Gas. The Board notes that this strategy addresses the direction outlined in Decision 2001-75 whereby the Board found that a mix of daily spot market purchases and daily and monthly index gas contracts was a reasonable utility gas portfolio. The Board also noted in that decision that long-term gas contracts that were already in place would be continued, but not renewed.

The Board notes Calgary's submission that DERS did not articulate its gas supply acquisition strategy and that prior to any Board approval, DERS should file a gas supply plan. The Board notes that ATCO Gas has never provided a detailed gas supply plan. The Board agrees with DERS that a rigid procurement strategy may not be beneficial to all parties under various operating conditions. As discussed below, the Board believes an enhancement to the monthly GCFR filings should provide adequate monitoring of the procurement activities for the regulated portfolio in order to ensure that DERS is acquiring gas supplies at reasonable prices.

With respect to Calgary's submission that DERS proposed to change the mix of daily and monthly purchases, the Board acknowledges that DERS made this suggestion, but the Board also notes that DERS indicated that it would discuss any proposed changes with stakeholders prior to any proposed implementation.

The Board notes Calgary's submission that relative to ATCO Gas, DERS was changing gas supply and management strategies because numerous supply contracts (Major Contracts[114]) would not be assigned. The Board also notes that the majority of the Major Contracts appear to be long-term contracts. As noted above, the Board expected that long-term gas supply contracts would be phased out over time and be replaced with a short-term mix of monthly and daily index purchases. The Board accepts DERS's position that customers will continue to receive the benefits and costs of all active Major Contracts, regardless of whether they are assigned to DEML or remain with ATCO Gas.

The Board directs DERS to submit as part of its February 2004 GCFR filing a schedule outlining the final outcome[115] of each Major Contract.

After considering all of the above, the Board concludes that the gas supply portfolios DERS proposes are reasonable.

With respect to DERS's gas purchasing activities, the Board notes Calgary's concern with DERS's proposal that its unregulated affiliate purchase gas for both regulated and unregulated entities. The Board also notes Calgary's concern with respect to the pooling of day gas purchases for the regulated and non-regulated entities.

With respect to the pooling of day gas purchases, the Board considers that the regulated (North & South)/non-regulated pooling concept is reasonable for DERS to implement in the approved test period as long as DERS maintains separate pools for gas sourced from NGTL, ATCO Pipelines North and ATCO Pipelines South, and as long as DERS generally follows ATCO Gas's process for allocating these supplies to the respective North and South portfolios.

However, in order to continue implementation of this pooling concept, the Board directs DERS to provide evidence in its next DRT application that demonstrates that neither the regulated or non-regulated entities are clearly benefiting from the process.

The Board considers that the information currently contained in ATCO Gas's monthly GCRR filings provides a reasonable mechanism to ensure that gas being purchased for regulated customers is being acquired at market price benchmarks. However, given that DERS proposed to pool day gas purchases with a non-regulated affiliate, the Board believes that the information contained in DERS's monthly GCFR filing should be enhanced to provide additional transparency to the procurement effort.

Therefore, the Board directs DERS to include in its monthly GCFR filings, separate schedules that show the actual day gas purchases in the reconciliation month.[116] In addition, the Board expects DERS to record its procurement protocol and activities in sufficient detail that would permit an audit that could be initiated by the Board at any time.

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[114] Major Contracts are included in Schedule 6.13 to the Gas Assets Transfer Agreement filed in the Retail Sale Application.

[115] DERS should confirm which contracts were assigned, which ones were not and a description of how ATCO has re-sold the gas under those contacts to DERS.

[116] For each day in each reconciliation month indicate the total day gas purchases (TJ), the total cost ($000), the average unit cost ($/GJ) and the AECO Daily Index price ($/GJ). The day gas purchases should also be reported (total TJ, total $, average $/GJ) separately for the Proprietary Supplies and Common Pool Supplies.

With respect to gas supply sources, the Board notes that DERS indicated that it would enter into structured peaking arrangements with certain major suppliers in order to increase security of supply for regulated customers and reduce administration effort and dependence on the NGX. The Board also notes that credit support costs are expected to be higher with the NGX then through arrangements with other gas suppliers.

Therefore, the Board directs DERS to demonstrate as part of its next DRT application that its use of the NGX and other gas counterparties is reasonable when considering overall costs and benefits to the regulated customers.

With respect to Calgary's submission that DERS proposed to modify ATCO Gas's monthly GCRR filing, the Board believes the record is fairly clear that DERS plans to follow the format and level of detail provided by ATCO Gas in its monthly filings.

However, in order to ensure that there is no misunderstanding, the Board directs DERS in its monthly GCFR filings to follow the format and level of detail provided by ATCO Gas, except for the additional day gas purchase schedules noted above, other schedules noted in this Decision and any other required differences that DERS can substantiate.

With respect to Calgary's submission that the Board should follow the mock GCRR procedure and direct DERS to follow a similar process, the Board does not believe the "mock approach" is required in the circumstances because interested parties have accepted ATCO Gas's current format and DERS will not be revising the information to any great extent. In addition, if parties do have a concern, they have the opportunity to express their concern to the Board during the normal 30-day review period.

With respect to the GCFR filings, the Board accepts DERS's proposal to be consistent with ATCO Gas and file information packages with the Board for acknowledgement on the fifth last business day of each month.

With respect to Calgary's submission that DERS proposed to become obligated to balance both ATCO Pipelines and ATCO Gas, the Board agrees with DERS that the review of any proposed changes will be dealt with in the ATCO Gas Retailer Service and GUA Compliance proceeding.

### 4.2.2 Energy Revenue Requirements

Table 19 shows the DRT energy related revenue requirements. In the DRT Application, the costs of credit charges, working capital, bad debt, and penalty revenue were allocated to both the energy and non-energy revenue requirements.

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The day gas purchases in the Common Pool Supplies should also be reported (total TJ, total $, average $/GJ) separately by instrument (Yesterday or Same Day).

Table 19. DRT Energy Revenue Requirements

| Categories | ($000s)<br>5 month test period | ($000s)<br>12 month test period |
|---|---|---|
| **Procurement and Portfolio Management** | $309 | $770 |
| Credit Charges | $1,242 | $2,964 |
| Working Capital | -$193 | -$458 |
| Bad Debt | $886 | $2,067 |
| Penalty Revenue | -$2,029 | -$4,737 |
| Total | $215 | $605 |

Note: DERS proposed that the forecast cost of the **bolded** category in this table be approved as final.

### 4.2.2.1 Procurement and Portfolio Management Costs

The Board addressed the procurement and portfolio management costs as part of the discussion on staff salaries in section 4.1.1.6.

### 4.2.2.2 Credit Charges

DERS forecast of energy credit charges for the DRT is set out in Table 19.

DERS indicated that energy credit charges for the DRT are related to the posting of parental company guarantees to gas supply counterparties and to approved financial institutions for the acquisition of letters of credit to allow DERS to conduct business on the NGX.

**Views of the Interveners**

**AUMA/CE**

AUMA/CE noted DERS's submission that 67 gas supply contracts would either be assigned to DEML or commercially reasonable arrangements between DEML and ATCO Gas would be entered into "...with no increase in price." AUMA/CE also noted DERS's comment that "...the costs and benefits of the balance of the Major Contracts would continue to flow to regulated customers through the GCFR". Based on these comments, AUMA/CE argued any credit charges associated with these contracts should not be approved.

**Calgary**

Calgary submitted that there were no details presented by DERS to demonstrate its forecast revenue requirements for Letters of Credit and Parental Guarantees related to the gas supply contracts. Calgary submitted that DERS did not provide any reasons why its cost of credit should be so much higher than ATCO Gas credit costs, as shown in its monthly GCRR filings. Calgary argued that consumers should not incur higher costs just because DERS could not make gas supply arrangements on the same basis as ATCO Gas.

With respect to credit charges for gas supply contracts, Calgary submitted that there was great uncertainty regarding the ultimate quantum of costs. Calgary argued that it was not clear whether the credit facilities would be used.

Given the above concerns, Calgary submitted that there should be a zero balance for inclusion in the revenue requirement related to the energy related credit charges. Calgary argued that if credit facilities were ultimately called upon, DERS should demonstrate that the costs were incurred prudently and then the deferral account could be adjusted for the costs.

### Consumer Group

The Consumer Group submitted the 12-month test period forecast of $2.9 million in credit charges was overstated. The Consumer Group argued that the forecast consumption requirements were augmented by 25% and high forward prices were utilized in the forecast. In its refiling, the Consumer Group submitted that DERS should be required to recalculate the amount required for credit support taking into account the above factors.

With respect to the NGX, the Consumer Group submitted that the Centrica plc approach of securing a Letter of Credit and then backing it with a Parental Guarantee amounted to double charging for the same service. The Consumer Group argued that Parental Guarantees may be posted in lieu of Letters of Credit and that this approach should be revisited with the NGX.

The Consumer Group submitted that the requirement for credit support had to be evaluated on a contract-by-contract basis to ensure the prudence of costs. To ensure such prudence, the Consumer Group suggested that a working group of Interveners plus a Board staff representative should monitor and approve the required level of credit support for each contract.

The Consumer Group submitted that it appeared that gas traders willing to deal with ATCO Gas may be unwilling to extend the same credit to DERS, without additional guarantees. The Consumer Group argued that customers should not be placed in the position of bearing the risks and additional costs associated with gas traders' perceptions of selling gas to DEML.

The Consumer Group noted DERS's suggestion that the cost of a combined Letter of Credit and Parental Guarantee was less than prepaying for gas or incurring working capital carrying costs but argued that there was no calculation on the record to supports this assertion. The Consumer Group submitted that prepayment of gas would be against normal industry practice and it would require offsetting favourable discounts to contract prices that would be a saving to customers.

The Consumer Group argued there was no real incentive for DEML or Centrica management to reduce the cost of gas supply to the regulated customer and that the higher the prudential costs of trading on the NGX, the higher the shadow profit Centrica would make from gas supply to its regulated subsidiary.

The Consumer Group recommended that the Board direct DERS to provide, as part of its monthly GCFR filing, a detailed reconciliation and substantiation in order to examine the prudence of daily credit levels.

The Consumer Group submitted that if ATCO Gas did not have credit requirements for the gas supply contracts to be assigned to DERS, then there should be no additional credit supplied by DERS for these same assigned contracts. The Consumer Group argued that inflated credit requirements only served to attract additional Parental Guarantee charges.

### Views of DERS

DERS noted that the proposed credit charges were the mathematical result of the application of the rate of 40 bps for Parental Guarantees to the forecast requirements for Parental Guarantees plus the application of the rate of 62.5 bps for Letters of Credit to the forecast requirements for Letters of Credit.

DERS indicated that it would manage its credit requirements for both Parental Guarantees and Letters of Credit to ensure that credit charges to regulated customers were minimized. DERS stated that Parental Guarantee charges would be updated each month, while the Letters of Credit posted with the NGX would be adjusted as frequently as was prudent, possibly on a daily basis.

DERS requested deferral account treatment for these costs. DERS submitted that only the actual incurred costs would ultimately be paid by customers.

With respect to gas supply counterparties, DERS proposed to use Parental Guarantees as much as possible, but noted that the NGX required a Letter of Credit from an approved financial institution. In order to obtain such a Letter of Credit, DERS stated that it must provide a Centrica Parental Guarantee to the issuing financial institution. DERS stated that this resulted in a combined credit charge related to the cost of the Parental Guarantee and the cost of the Letter of Credit issued by the approved financial institution. DERS argued that this cost was less than the alternative cost of prepaying for the gas and incurring high working capital carrying costs.

DERS noted that it would likely be required to post Parental Guarantees to gas supply counterparties for the contracts assigned from ATCO Gas in excess of the credit support required from ATCO Gas under those contracts. DERS submitted that this was reflective of the current credit requirements in the energy industry as well as a result of the assignment provisions under those contracts. DERS stated these credit costs would be minimized through the posting of Parental Guarantees in lieu of Letters of Credit, where acceptable to the counterparty.

DERS noted Calgary's assertion that the applied-for credit charges for the most part were not incurred by ATCO in the provision of regulated service and submitted that there was no evidence on the record to show that ATCO Gas did not recover credit costs through the use of working capital to pre-pay gas purchases. DERS argued that the small amount of credit charges shown in the ATCO Gas monthly GCRR filings did not accord with what DERS knew to be the cost of credit associated with procurement of the regulated gas portfolio's requirements.

DERS noted the AUMA/CE suggestion that because any benefits or costs associated with assignable contracts would continue to flow to regulated customers, that any credit charges associated with those contracts must be ignored. DERS submitted that this conclusion was based on an incorrect and illogical connection between the referenced comments, which must be taken in the context of referring to the pricing and volume arrangements under the contracts, and the credit postings, if any, that will be required in order for the contract counterparties to agree to assign the contracts to DERS. DERS stated that it was not known at this time to what extent these counterparties will require some form of credit to be posted.

DERS also noted the Consumer Group statement that there was no evidence on the record to indicate what level of credit support was required by ATCO Gas to transact on the NGX. DERS agreed that this was true, but submitted that it was clear that the NGX required Letters of Credit or prepayment, which would increase working capital requirements, on all transactions.

DERS noted the Consumer Group suggestion that the credit amount of $282 million was overstated because 50% of the estimated value of the annual portfolio would be for spot gas purchases and not be subject to an annual credit amount requirement. DERS submitted that this suggestion was inaccurate because spot or Daily Index gas incurred a credit charge as it was an accounts receivable risk to the party supplying the gas. DERS stated that the industry standard was to pay for all gas purchases (spot or monthly index) on the 25th day of the month following flow day. DERS argued that there was credit risk to the supplying party until the gas was paid for that it must properly manage by requiring credit support from the counterparties with which it transacted.

DERS argued that the Consumer Group suggestion, that a working group should assess DERS's credit charges and assignments on a contract by contract basis, amounted to micro-management and was unnecessary in light of the monthly GCFR filings that would be made by DERS.

### Views of the Board

As discussed in section 4.3.2 (Deferral Accounts), the Board has approved the use of an energy deferral account for the credit charges discussed in this section.

The Board notes that DERS has indicated that it intends to supply DRT customers through gas purchases from the NGX, gas purchases from gas supply contracts assigned from ATCO and DEML gas supply contracts.

With respect to the NGX, the Board notes that DERS indicated that the NGX required a Letter of Credit from an approved financial institution and in order to obtain such a Letter of Credit, DERS stated that it must provide a Centrica Parental Guarantee to the issuing financial institution. With respect to the Consumer Group's submission that Parental Guarantees may be posted in lieu of Letters of Credit with the NGX, the Board notes that since July 2002 the NGX has required all parties to post collateral in the form of a cash margin or a Letter of Credit from an approved financial institution.[117]

With respect to credit support requirements for the gas supply contracts assigned from ATCO Gas, the Board notes that DERS indicated that it would likely be required to post Parental Guarantees to gas supply counterparties in excess of the credit support required from ATCO Gas. The Board also notes that AUMA/CE and the Consumer Group argued that credit charges associated with these gas supply contracts should not be approved.

However, the Board does not consider the amount of credit support that ATCO Gas was required to provide to be relevant to the question of whether it is reasonable for DERS to provide credit support. The Board notes the following exchange between DERS and Board Counsel with respect to the gas supply contracts that may be assigned to DEML from ATCO Gas:

> Q. Sir, can you confirm that Direct Energy will only be required to provide parental guarantees or letters of credit to counterparties for those assigned contracts in situations where ATCO was also required to provide such security?

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[117] Revised Evidence of William G. Foster, September 2003. p. 10

> A. We cannot make that confirmation, sir, for two reasons. First of all, some of those contracts do not have assignment clauses, therefore, the counterparty can withhold agreements to assign unless it receives what they would consider as appropriate security and then the assignment becomes no different from entering into a negotiated agreement with that third party. Secondly, most of the other contracts include clauses to the effect that they can't be reasonably -- that assignment cannot be unreasonably withheld. That test has typically required us to provide parental company guarantees as part of the reasonableness test. As I've said, credit support is required in today's energy markets. It is a feature of the vast majority of energy procurement that we do across the whole of North America and most counterparties are aware of the issue.
>
> Q. Sir, are you aware, today, prior to the actual assignments taking place, of any of those contracts which are going to be assigned from ATCO, whether guarantees will be required or letters of credit will be required, whether or not presently required from ATCO? Ms. Halwas, perhaps
>
> A. We are not aware of the credit arrangements that ATCO has with each of those counterparties. It is not -- that is not unusual in today's marketplace. I would add that if we're not able to negotiate an agreement on credit with any of those counterparties, we would have to seek to procure the related gas from third parties where we would almost certainly require parental company guarantees. I can confirm, though, that, if possible, we will seek to avoid parental company guarantees but that is a very, very rare event in today's energy markets.[118]

The Board also notes DERS submission that some small producers have not asked for Parental Guarantees.[119]

The Board notes that no intervener submitted that credit support was not required in today's energy industry. Interveners only argued that if ATCO Gas did not incur credit support costs, then DERS should not be allowed to recover credit support costs. The Board considers it reasonable to expect that DERS on a stand-alone basis may have to provide credit support for some assigned contracts. However, the Board expects DERS to manage the negotiations with respect to these contracts in order to minimize overall costs to customers.

The Board notes the Consumer Group submission that the change in the level of credit required by contract, from what it was under ATCO to what it is under DERS, should be provided in a refiling with confidentiality respected by simply numbering the contracts.

While the Board will not require DERS to provide the level of credit required by contract, the Board directs DERS to include in its monthly GCFR filing a schedule that shows credit support expenses for three components: the NGX, contracts assigned by ATCO Gas, and other gas supply contracts.

With respect to the forecast quantum of credit support, the Board notes that Calgary and the Consumer Group were concerned with DERS's forecast and that the Consumer Group argued that DERS should refile its credit support forecast. The Board agrees with DERS that credit charges will be determined on an ongoing basis reflecting gas supply volume requirements and gas prices.

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[118] Tr. pp. 1159 - 1161

[119] Tr. p. 1154

With respect to the proposed forms of credit support, the Board notes that it appears that DERS has no choice but to use a Letter of Credit backed by a Parental Guarantee for the NGX. Therefore, the Board considers this form of credit support is reasonable for the NGX. For the assigned contracts and other gas supply contracts, the Board notes that DERS plans to use Parental Guarantees in lieu of Letters of Credit where acceptable to the counterparty. Since the approved Parental Guarantee charges are lower than the Letter of Credit charges as noted in section 2.5, the Board considers that DERS's planned approach is reasonable when considering DERS on a stand-alone basis.

With respect to actual booking of Parental Guarantee charges and Letters of Credit charges to the DGA, the Board expects DERS to implement the activities described during the hearing.[120]

### 4.2.2.3 Working Capital Costs

DERS noted that the working capital requirements in the energy revenue requirement related solely to gas costs. DERS requested deferral account treatment for these costs and stated that customers would ultimately pay only actual incurred costs.

The Board considers DERS's proposed method of calculating energy-related working capital requirements to be reasonable and the Board accepts DERS's proposed method for the purposes of this Decision. The Board notes that no intervener objected to the DERS's proposed method of calculating energy-related working capital requirements.

### 4.2.2.4 Bad Debt Expense

#### Views of the Interveners

#### Calgary

Calgary stated that it accepted the original allocation of bad debt expense between non-energy and energy revenue requirements since the calculation was consistent with the methodology used to allocate penalty revenue.

Calgary submitted that the amounts included in the revenue requirement should serve only as a placeholder with deferral account treatment. Calgary argued that in order to ensure precise and appropriate apportionment, each bad debt expense amount should be allocated monthly using the proportion of revenues related to each of the GCRR and amounts related to the ATCO Gas distribution charge.

Calgary submitted that it was essential that appropriate allocations for bad debt expense were made monthly between regulated and unregulated businesses, and that to ensure proper allocations, the revenues or the weighted volumes of gas in each of regulated and unregulated business units by rate class should be used.

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[120] Tr. pp. 1154-1155, 1157-1159

### Views of DERS

DERS noted that its forecast DRT bad debt expense was at 0.22% of total revenue.[121] DERS stated that bad debt expense was allocated between the energy and non-energy revenue requirements on the basis of the relative energy and non-energy revenue requirements. DERS therefore allocated 67.8% of bad debt expense to the energy revenue requirement[122] and the balance to the non-energy revenue requirement.

DERS proposed that bad debt expense be subject to deferral account treatment so that the actual bad debt costs would ultimately be paid by customers.

DERS noted that Calgary supported its proposal to allocate bad debt expense between the energy and non-energy revenue requirement, but that Calgary proposed that this allocation be updated monthly. DERS submitted that this refinement was unnecessary in view of the proposed deferral account treatment and the negligible impact this refinement would have on monthly energy charges.

DERS also noted Calgary's suggestion that bad debt expense be allocated monthly between regulated and unregulated businesses based on the weighted volumes of gas acquired for regulated and unregulated purposes. DERS argued that no such allocation was necessary since bad debts were specific to individual customers, either regulated or unregulated.

### Views of the Board

In section 4.3.2, the Board has approved the use of a deferral account for DRT bad debt expense.

The Board considers DERS's forecast of DRT bad debt expense to be reasonable, and notes that no interveners commented on this matter.

The Board notes that Calgary accepted DERS's original allocation of bad debt expense between non-energy and energy revenue requirements and the Board also notes that DERS updated its original allocation using the same methodology. The Board considers the method of allocating bad debt expense between non-energy and energy revenue requirements to be reasonable.

The Board agrees with DERS that Calgary's proposal to allocate each bad debt expense amount between the energy and non-energy deferral accounts monthly is an unnecessary refinement in view of the deferral account treatment and the negligible impact this refinement would have on monthly energy charges.

The Board agrees with DERS that no monthly allocation of bad debt expense between regulated and non-regulated businesses is required because bad debts are specific to individual customers and DERS must keep separate records for its regulated and non-regulated businesses.

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[121] Total revenue defined as DERS' DRT forecast non-energy requirements and forecast gas costs plus AG's forecast distribution tariff revenue. See Exhibit 002-02, AUMA/CE-DERS (DRT) 23(s); Exhibit 005-40, DRT Revenue Requirement Reconciliation, Note 2.

[122] Exhibit 005-40, DRT Revenue Requirement Reconciliation, Note 2

#### 4.2.2.5 Penalty Revenue

**Views of the Interveners**

**Calgary**

Calgary stated that it accepted the original allocation of penalty revenue between non-energy and energy revenue requirements, since the calculation was consistent with the methodology used to allocate bad debt expense.

Calgary submitted that the amounts included in the revenue requirements should serve only as a placeholder with deferral account treatment. Calgary argued that in order to ensure precision and appropriate apportionment, each penalty revenue amount should be allocated monthly using the proportion of revenues related to each of the GCRR and amounts related to the ATCO Gas distribution charge.

Calgary submitted that it was essential that appropriate allocations for penalty revenue were made monthly between regulated and unregulated businesses, and that to ensure proper allocations, the revenues or the weighted volumes of gas in each of regulated and unregulated business units by rate class should be used.

**Views of DERS**

DERS submitted that its forecast DRT penalty revenue of 0.5% of total revenue[123] was based on ATCO Gas's historical experience. DERS stated that penalty revenues were allocated between the energy and non-energy revenue requirements on the basis of the relative energy and non-energy revenue requirements. DERS therefore allocated 67.8% of DRT penalty revenue to the DRT energy revenue requirement[124] and the balance to the non-energy revenue requirement. DERS proposed that penalty revenue be subject to deferral account treatment so that the actual penalty revenue would ultimately be credited to customers.

DERS noted that as a result of consultations with customer representatives, it was proposing that penalty revenue should be assessed at 1.5% per month on the outstanding balance rather than on the basis of a one-time 5% late payment penalty. DERS submitted that this change would have no effect on forecast penalty revenue.

**Views of the Board**

In section 4.3.2 of this Decision, the Board has approved the use of a deferral account for DRT penalty revenue.

The Board considers DERS's forecast of DRT penalty revenue to be reasonable, and notes that no interveners commented on this matter.

The Board considers DERS's proposed method of assessing penalty revenue to be reasonable, and notes that no interveners commented on DERS's proposal that penalty revenue be assessed at 1.5% per month on the outstanding balance.

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[123] Exhibit 002-02, ARUA-DERS-17(k)

[124] Exhibit 005-40, DRT Revenue Requirement Reconciliation, Note 2

The Board notes that Calgary accepted DERS's original allocation of penalty revenue between non-energy and energy revenue requirements and the Board also notes that DERS updated its original allocation using the same methodology. The Board considers the method of allocating penalty revenue between non-energy and energy revenue requirements to be reasonable.

The Board agrees with DERS that Calgary's proposal to allocate each penalty revenue amount between the energy and non-energy deferral accounts monthly is an unnecessary refinement in view of the deferral account treatment and the negligible impact this refinement would have on monthly energy charges.

The Board agrees with DERS that no monthly allocation of penalty revenue between regulated and non-regulated businesses is required because late payment charges are specific to individual customers and DERS must keep separate records for its regulated and non-regulated businesses.

### 4.2.3 Other Gas Cost Flow-Through Components

The other gas cost flow-through components are listed in section 4.3.2 and the Board has provided comments and/or directions with respect to these components in that section.

### 4.2.4 Gas Cost Flow-Through Rate (Rider F)

DERS noted that it filed a pro-forma GCFR and DGA reconciliation in the proceeding.[125]

#### Views of the Interveners

Views from Calgary and DERS with respect to this matter have been discussed in section 4.2.1 of this Decision.

#### Views of the Board

The Board considers the calculation methodology with respect to the GCFR to be reasonable. The Board has attached the Rider "F" Schedules in Appendix 6 and 7 of this Decision.

## 4.3 Other Matters

### 4.3.1 Customer and Load Forecasts

DERS forecast total number of DRT customer months and corresponding consumption (sales or load) for five-month and twelve-month test periods for eight customer classes and grouped them into the three rate classes shown in Table 20. The period from August to December 2003 was used as the basis for the five-month test period and calendar 2004 was used as the basis for the twelve-month test period.

DERS indicated that it used the same number of monthly customers and energy consumption by customer class that ATCO Gas used in its 2003-2004 GRA except for residential customers.

To calculate the total number of DRT customers and the corresponding energy consumption, DERS indicated that it used a two-step approach:

- determination of the total customers within each customer class; and

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[125] BR-DERS-37 in Exhibit 002-02

- retention analysis of the DRT customers by customer class to determine the number of DRT customers in each class.

DERS noted that all customers currently served under ATCO Gas's Rates 1, 3, and 5 are eligible for DRT service.

The results of DERS's forecasts are shown in Table 20 and these results were used to allocate non-energy revenue requirements to the various rate classes.

**Table 20. DRT Cost Allocators by Rate Class**[126]

| 5-Month Test Period | | | | | | |
|---|---|---|---|---|---|---|
| Rate Class | No. of DRT Customers Months | % | No. of DRT Bills after Consolidating Billing (#/year) | % | DRT Sales (TJ/year) | % |
| General Service G1 | 4,012,702 | 99.71 | 4,012,702 | 99.71 | 66,757 | 83.69 |
| Large Use Service G3 | 8,268 | 0.21 | 8,268 | 0.21 | 12,418 | 15.80 |
| Irrigation Pumping G5 | 3,405 | 0.08 | 3,405 | 0.08 | 401 | 0.51 |
| | 4,024,375 | 100.00 | 4,024,375 | 100.00 | 78,576 | 100.00 |

| 12-Month Test Period | | | | | | |
|---|---|---|---|---|---|---|
| Rate Class | No. of DRT Customers Months | % | No. of DRT Bills after Consolidating Billing (#/year) | % | DRT Sales (TJ/year) | % |
| General Service G1 | 9,648,544 | 99.71 | 9,648,544 | 99.71 | 159,486 | 83.09 |
| Large Use Service G3 | 19,938 | 0.21 | 19,938 | 0.21 | 31,664 | 16.50 |
| Irrigation Pumping G5 | 8,311 | 0.09 | 8,311 | 0.09 | 787 | 0.41 |
| | 9,676,793 | 100.00 | 9,676,793 | 100.00 | 191,937 | 100.00 |

## Views of the Interveners

### Calgary

Calgary submitted that it had a number of concerns with DERS's customer forecast since it was based on inconsistent information provided by ATCO Gas in its 2003-2004 GRA proceeding and through information requests in this proceeding. Calgary conducted its own analysis of customer counts and argued that the customer count utilized by DERS for the five-month test year in 2003 was understated by 37,794 customers or 188,970 bills. For the 2004 test year, Calgary submitted that DERS's customer count was understated by 54,842 customers or 658,104 bills.

Calgary submitted that DERS presented no evidence or information which refuted its customer count analysis and Calgary argued that the Board should accept its customer count when evaluating the DERS application.

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[126] From Exhibit 005-40, Schedule 7.1

In terms of final rate design, Calgary submitted that actual customer count data at the time of the implementation of the transfer be utilized for determining initial rates and charges to be utilized by DERS. Calgary further submitted that the determination of the number of customers who will switch to unregulated service for each of the test periods be based upon ATCO Gas's actual experience at the time of implementation of the transfer.

### Views of DERS

DERS noted Calgary's suggestion that DERS's forecast of average DRT customers and associated consumption over the test period was understated. DERS also noted Calgary's submission that the DRT fixed monthly charge and energy charge should be reduced by 4.49% and 6.37% for the five-month and twelve-month test periods, respectively, due to Calgary's increased average customer count.

DERS submitted that it was clear that Calgary's evidence only accounted for the increase in revenue from these additional customers and did not account for the increase in costs to serve these additional customers.

DERS noted Calgary's suggestion that rates should be based on actual customer count data as at the time of transfer but DERS argued that there was no evidence to support Calgary's suggestion of increased accuracy in rates by adjusting to actual customer count on the date of transfer.

DERS submitted that actual average number of customers over the test periods would be different than either the DERS or Calgary forecasts and it was for this reason that DERS proposed a revenue deferral account and cost deferral accounts for those costs that are dependant upon customer behaviour. DERS argued that Calgary's incorrect calculations provided no basis to adjust DERS's proposed rates and a minor last minute adjustment to rates, as suggested by Calgary, was not warranted in light of the deferral account treatment proposed by DERS.

### Views of the Board

The Board notes that DERS established customer and load forecasts for the same customer classes used by ATCO Gas in its 2003-2004 GRA. The Board also notes that DERS used the same number of monthly customers and energy consumption by customer class except for the residential customers. The Board notes that in Decision 2003-072, ATCO Gas's customer growth and use per customer forecasts were accepted as filed for all classes. The Board also notes Calgary's submission that DERS understated its customer count forecast.

The Board notes that the differences between forecast and actual number of customers and sales will impact revenues and costs. However, the Board also recognizes that the forecast and actual non-energy revenues and costs will be reconciled in the non-energy revenue deferral account and certain cost deferral accounts. In addition, the Board notes that differences between forecast and actual gas purchases will be reconciled through the DGA.

With respect to the calculation and disposition of non-energy deferral accounts, the Board notes that DERS indicated that it would use actual customer numbers, actual sales and actual revenue by rate class in the reconciliation process.[127]

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[127] AUMA/CE-DERS (DRT)-13

With respect to Calgary's concern regarding the reasonableness of the customer count forecast, the Board agrees with DERS that it appears that Calgary did not consider the implications of its customer count increase on forecast costs. The Board also agrees with DERS that the actual average number of customers will probably be different than either the DERS or Calgary forecast.

Recognizing that virtually all revenues and costs that vary with customers or sales will be subject to deferral account treatment, the Board does not consider that any adjustment to the forecasts prepared by DERS is necessary for the purposes of this Decision.

However, with respect to the DGA, the Board expects DERS to update its load forecast (calendar sales) on a monthly basis with the best available information.

### 4.3.2 Deferral Accounts

DERS proposed that energy and non-energy cost deferral accounts be used for its DRT. Table 21 below shows the proposed deferral accounts and the cost categories that DERS requested final approval for in its cost forecast. Table 11 shows the forecast revenue requirements associated with the deferral and non-deferral, non-energy revenue requirement items. Table 19 shows the forecast revenue requirements associated with the deferral and non-deferral, energy revenue requirement items. DERS proposed to use a revenue deferral account for energy and non-energy.

**Table 21. DRT Deferral and Non-Deferral Accounts**

| Category | Cost |
|---|---|
| ***Energy Categories*** | |
| Procurement and Portfolio Management | Non-Deferral |
| Credit Charges | Deferral |
| Working Capital | Deferral |
| Bad Debts | Deferral |
| Penalty Revenue | Deferral |
| | |
| ***Non-Energy Categories*** | |
| Customer Care Costs | Deferral |
| Amortization of Integration Costs[128] | Non-Deferral |
| Working Capital | Deferral |
| Credit Charges | Deferral |
| Amortization of Hearing Costs | Deferral |
| Other Operating Costs | Non-Deferral |
| Bad Debts | Deferral |
| Penalty Revenue | Deferral |

Source: Exhibit 005-40, DRT, Table 3.1

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[128] The time value benefit included in Integration costs will be subject to deferral account treatment.

## Energy Related Deferral Account

For its energy deferral account, DERS proposed to maintain the structure of ATCO Gas's existing Deferred Gas Account (DGA). DERS noted that its opening balance for the DGA accounts will equal ATCO Gas's closing DGA balances as outlined in the GATA.[129] DERS also noted that ATCO Gas will remain the party responsible for any prior period adjustments to its DGA made subsequent to the Adjustment Time described in the GATA. DERS noted that as any such adjustments are made and approved by the Board, they will be transferred to DERS's DGA and DERS will reflect these adjustments in its GCFR.[130]

DERS proposed to use the same flow-through pricing model for calculating its GCFR as ATCO Gas uses for its GCRR. DERS noted that the intent of the mechanism was to pass on actual gas costs to customers. DERS also noted that the monthly GCFR would be determined by taking into account the forward market prices of gas for its gas supply portfolio components and the prior period recoveries and costs included in the DGA.

DERS proposed to maintain the current configuration of separate GCFR's and separate DGA's for the service territories of ATCO Gas North and South.

DERS noted that in addition to the items outlined in Table 21, the following components would also be included in the DGA as appropriate.[131] DERS also noted that the forecast, estimate and actual numbers for the following components would be updated monthly:

- Gas purchases
- Imbalances
- Fuel
- Transportation
- Rider D and TCPL (AB) Fuel Recovery
- Calendar Sales
- Exchange Service
- Transportation Imbalance Sales
- Excess System Sales

In the Application, DERS proposed that the energy-related components of credit charges, working capital, bad debt and penalty revenue would be subject to reconciliation as outlined in Decision 2003-015[132] and would be reconciled annually in the March information package. DERS noted that any accrued differences in these costs will be recovered in the month of March. However, DERS also noted that the adjustment frequency for credit charges would be monthly and that carrying costs or credit would be determined for DGA balances on a monthly basis and included in the determination of the GCFR.[133]

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[129] The Gas Assets Transfer Agreement was filed as part of the Retail Sale Application.

[130] BR-DERS-8

[131] DERS noted that, although Procurement and Portfolio Management costs would be included as one of the components included in the derivation of its monthly GCFR, it requested final approval of its forecast instead of deferral account treatment.

[132] Decision 2003-015 – ATCO Gas, Reconciliation Process for Certain Costs and Revenues Charges to the Gas Cost Recovery Rate and Company-Onwed Storage Rate Rider, dated February 18, 2003

In the hearing, DERS stated that Parental Guarantee charges will be updated each month[134], while the Letters of Credit posted with the NGX would be adjusted as frequently as was prudent, which possibly included on a daily basis.[135]

### Non-Energy Deferral Accounts

As shown in Table 21, DERS proposed to have six cost categories included in non-energy deferral accounts. DERS proposed to revise the forecast numbers for the non-energy deferral account items on an annual basis. However, if deferral accounts accumulate balances exceeding +/- 10% of the forecast revenue requirement, DERS indicated that it would apply for an early disposition of the deferral account balances and an adjustment to the non-energy rates for an appropriate period of time.[136]

DERS submitted that the 2004 non-energy deferral account balances were anticipated to be final by March 1, 2005 and following that date, DERS proposed to file an application with the Board for approval of the final disposition of the accrued balance in each 2004 deferral account.

### Views of the Interveners

### AUMA/CE

AUMA/CE submitted that the Amortization of integration costs and other operating costs should be treated as Deferral accounts and the costs should be recovered on the basis of necessary and prudent costs incurred. AUMA/CE outlined the following reasons for its position:

- DERS had no previous regulatory experience in Canada;
- DERS has no track record of forecasting regulatory costs prior to the filing of the Application;
- DERS's limited track record of forecasting these costs during the proceeding was poor; and
- the allocation of costs between regulated and non-regulated was untested and arbitrary.

AUMA/CE submitted that to help ensure that the proper amounts of regulated costs are being charged to regulated customers, DERS should be directed to either require the use of timesheets by all regulated staff (both DEML and Corporate) or at a minimum, conduct "time in motion" studies for at least one year to further verify the allocation of costs between regulated and non-regulated categories. AUMA/CE stated that these studies should be filed with DERS's next rate application to provide parties with some confidence in DERS's allocation of regulated versus non-regulated costs.

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[133] DRT Application, p. 5-2 to 5-3

[134] Tr. p. 1155

[135] Tr. pp. 1157-1159

[136] Exhibit 002-02, BR-DERS-7

For the remaining cost and revenue categories, AUMA/CE was not opposed to the use of deferral accounts as proposed by DERS. While generally supportive of the annual adjustments proposed for the RRT cost and revenue categories, AUMA/CE supported the proposal by DERS that includes a "trigger" mechanism that would require true-up of the cost or revenue category on a more frequent basis if the difference between forecast and actual was above certain limits.

### Calgary

Calgary submitted that the deferral accounts eliminate almost all of the risk to DERS and that customer switching was largely in the control and under the influence of DEML affiliates.

Calgary submitted that competitors would not have the benefit of offsetting risk with deferral accounts and Calgary argued that without the use of deferral accounts, competitors would have increased costs above that of DERS.

### Consumer Group

The Consumer Group noted that it was concerned that the flow-through of certain controllable costs will result in a lack of incentive on the part of DERS to effectively manage these costs. The Consumer Group stated that customer care costs were of particular concern and noted that its concerns might be mitigated if the Board directed DERS to provide the following information at the time of its refiling:

- historical I-Tek activity levels for various billing determinants as applicable;
- justification if the DERS forecasts are higher than historical billing determinants; and
- a proposed management incentive package that would provide management with an appropriate incentive to manage and minimize each controllable customer care cost.

The Consumer Group submitted that any deferral account opening balances taken over by DERS from ATCO should be subject to audit verification in order to avoid subsequent questions concerning the accuracy of amounts. The Consumer Group stated that DERS did not provide detailed formulas showing how the amounts transferred to or from the various energy and non-energy deferral accounts would be calculated and submitted that the Board should direct DERS to file this information in order to avoid future confusion on how deferral accounts will be trued up to actual numbers.

Given the magnitude of various deferral accounts, the Consumer Group stated that the details of amounts reflected in deferral accounts should be subject to review and confirmation by the Company's external auditors to ensure DERS is in compliance with Board precedents for calculation of gas and energy deferral accounts, as well as any other conditions established or accepted by the Board for each account.

The Consumer Group noted that they did not disagree with the 10% trigger point threshold for non-gas deferral accounts and RRT deferral accounts. The Consumer Group submitted that any interest on deferral accounts should be subject to the guidelines provided in IL 2000-1.[137]

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[137] Information Letter IL 2000-1 dated February 16, 2000 – General Policy for Payment of Interest

The Consumer Group recommended that any communication costs allowed by the Board should be treated on a deferral basis because these costs were dependent on expenditure levels of other entities, such as ATCO and the Government.

The Consumer Group noted that DERS stated that as customers switch to unregulated suppliers, responsibility for these customers' customer care, distribution tariff and franchise fee payments, PEP account balances, deposits, bad debt and penalty revenue will shift from DERS to the customers' retail service provider. The Consumer Group noted that in conjunction with this shift in responsibility, DERS will no longer incur these costs on behalf of the switched customers.

The Consumer Group submitted that certain other costs treated on a forecast basis and whose allocation was dependent directly or indirectly on customer numbers would not be subject to the self correcting mechanism described by DERS. Therefore, the Consumer Group recommended that the allocation of integration costs, staff salaries, administration and corporate costs should be updated at least annually based on current circumstances for subsequent years' forecasts.

**Views of DERS**

DERS submitted that deferral accounts have been proposed for those cost items that vary with customer behavior or energy prices and argued that deferral accounts were appropriate for the types of costs proposed for deferral treatment, particularly during times of transition. DERS also stated that the deferral accounts were likely appropriate on an ongoing basis given the nature of DERS's cost-based approach to regulated service.

DERS stated that deferral accounts ensure that customers pay no more or no less than the actual costs incurred to provide service. DERS submitted that this was entirely appropriate for costs that vary either with energy pricing or customer behavior, both of which DERS argued were beyond the direct ability of DERS to control or to forecast with required accuracy.

DERS also submitted that deferral accounts do not, however, mitigate management's responsibility to manage the costs in a prudent manner and DERS noted that the management of DERS will remain accountable to the Board for the prudence of all costs incurred in the provision of regulated service.

DERS submitted that it faced significant uncertainty concerning the number of DRT customers that may switch to unregulated retailers during the 2003 and 2004 test periods and that this uncertainty could lead to the under-recovery or over-recovery of DERS's revenue requirement. DERS stated that the uncertainty was due to two principal factors:

- the lack of market history under the amended GUA and the *DGS Regulation*; and
- the increase in competition arising from the entry of competitors in the retail gas market.

DERS submitted that it would be appropriate for the Board to approve the applied-for deferral accounts and DERS's proposal for disposition of such deferral accounts.

DERS submitted that since one of the objectives of the Alberta Government's retail market refinement policy was to better align natural gas and electricity customer choice, for matters such as the use of deferral accounts, regulated retail gas service providers should strive to be consistent with relevant precedents that have governed the RRO for electricity. DERS argued that since the Board directed ATCO Electric to maintain deferral accounts in respect of certain non-energy revenue requirement items in Decisions 2000-88 and 2002-85, DERS proposed to utilize deferral accounts for those same non-energy revenue requirement items for the gas DRT. DERS submitted that this was consistent with the current mechanisms utilized for ATCO Gas's DGA.

DERS noted AUMA/CE suggestion that DERS's entire revenue requirement be subject to deferral account treatment and DERS submitted that AUMA/CE made this suggestion based on its mischaracterization of DERS's attempts to place the best and most current information on the record as an inability to forecast. DERS submitted that updating of forecasts, as additional or revised information comes to light, was an accepted practice by the Board and the suggestion by AUMA/CE was inappropriate and should be disregarded.

DERS also noted that AUMA/CE suggested that additional cost deferral accounts were required because DERS allocations between regulated and unregulated business functions were "arbitrary". DERS argued that these allocations were anything but arbitrary and were the result of the rigorous process. DERS did not agree with AUMA/CE's suggestion that either time sheets or "time in motion" studies were required to support the allocations proposed by DERS because the likely cost and administrative burden of either option would outweigh any perceived improvements in allocation accuracy relative to the process undertaken by DERS in support of the proposed allocations.

DERS did not agree with the Consumer Group's suggestion that, since customer education and energy awareness costs were dependant on expenditure levels of other entities such as ATCO and the government, these costs should be subject to deferral account treatment. DERS argued that this statement was incorrect and unsupportable based on the record for the Application.

### Views of the Board

The Board notes that the interveners were generally not opposed to the cost categories that DERS proposed to include in the deferral accounts.

The Board notes that for the DGA, DERS has proposed to include the same cost categories that the Board has previously approved for ATCO Gas except for credit charges. The Board notes that prior to ATCO Gas's monthly GCRR process[138] it had not explicitly approved recovery of credit support costs through the GCRR. However, the Board has accepted the noted Letter of Credit fees in ATCO Gas's monthly filings since November 2002.

With respect to the cost categories proposed to be included in non-energy deferral accounts, the Board notes that DERS proposed to use non-energy deferral accounts for the same cost categories previously approved for ATCO Electric for its RRO. However, the Board also notes that DERS proposed to include additional cost categories in non-energy deferral accounts, including credit charges and customer care costs. In its 2003 RROT Non-Energy Cost Application, ATCO Electric requested fixed cost deferrals for credit and collections, the credit management system and a few other items. ATCO Electric also noted in its application that it had initiated negotiations with ATCO I-Tek Business Services to replace existing contracts and as such, its forecast Customer Accounting costs should be treated as placeholders. On

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[138] Monthly GCRR implemented April 2002

December 11, 2002, the Board issued Decision 2002-105 that included interim 2003 RRO Non-Energy Rates for ATCO Electric.

The Board notes DERS's submission that deferral accounts were proposed for cost categories that vary with customer behaviour and energy prices, and that these variables were beyond the direct ability of DERS to control or to forecast with required accuracy. With respect to forecast accuracy, the Board is less concerned with accuracy when the cost category is included in a deferral account because customers will only incur actual costs. However, the Board also expects reasonable accuracy so that rates derived on the basis of these forecasts are fairly accurate so that future rate adjustments are minimized.

Given the uncertainty concerning the number of DRT customers that may switch to unregulated products, and given that DERS has not requested a return or margin for performing the DSP function, the Board approves deferral account treatment for the requested cost categories.

The Board agrees with DERS's submission that deferral accounts do not mitigate management's responsibility to manage the costs in a prudent manner and that the management of DERS will remain accountable to the Board for the prudence of all costs incurred in the provision of regulated service.

With respect to assignment of the cost categories to energy and/or non-energy deferral accounts, the Board notes that no intervener objected to the assignment of the cost categories to the respective energy and non-energy deferral accounts as proposed by DERS. Therefore, the Board approves the assignment of the cost categories to the respective energy and non-energy deferral accounts as proposed by DERS.

With respect to the DGA and the requested reconciliation and rate adjustment frequency, the Board notes that the GCFR will be revised monthly and that DERS proposed to adjust the forecast and actual numbers for most components in the DGA on a monthly basis. The Board notes that DERS proposed that other components (working capital, bad debts and penalty revenue) of the DGA would be subject to reconciliation as outlined in Decision 2003-015 and would be reconciled annually in the March information package. With respect to credit charges, the Board notes the apparent conflict in the evidence with respect to the requested reconciliation frequency.

In order to provide clarity, the Board directs DERS to implement the following reconciliation procedures for the working capital, bad debt and penalty revenue in the DGA:

- Use the approved forecast revenue requirements and include a prorated monthly amount of this approved forecast in the monthly GCFR filings.
- In the March 2005 GCFR information package, provide a detailed reconciliation of the forecast and actual monthly amounts.
- Include any differences between the actual amount and forecast amount that was used to determine the monthly GCFRs in the test period, in the derivation of the March 2005 GCFR.
- If such reconciling amounts cause a difference of greater than 3% to the GCFR otherwise determined for March 2005, the adjustment should be applied reasonably over the remaining months of the then current calendar year in a manner acceptable to the Board.

The Board also directs DERS to implement the following reconciliation procedures for the credit charges and the other cost categories in the DGA:

- in the monthly GCFR filings, update forecast, estimated and actual numbers using the best available information.

The Board believes that these procedures provide a reasonable trade off between an accurate GCFR and administrative and regulatory effort and cost

With respect to the non-energy deferral accounts and the requested reconciliation and rate adjustment frequency, the Board notes that DERS proposed to revise the forecast numbers for the non-energy deferral account items on an annual basis and if the deferral accounts accumulate balances exceeding +/- 10% of the forecast revenue requirement, DERS indicated that it would apply for an early disposition of the deferral account balances and an adjustment to the non-energy rates for an appropriate period of time.[139] The Board notes DERS's submission that approximately 80% of the total non-energy revenue requirements will be self-correcting as customers switch to unregulated suppliers. The Board also notes that AUMA/CE and Consumer Group did not oppose the proposed method for reconciling and adjusting the non-energy deferral account items. The Board considers that the additional administration and regulatory costs required for monthly rate adjustments would not justify the possible increased accuracy in rates. Therefore, the Board approves DERS's requested reconciliation and rate adjustment frequency and 10% trigger mechanism for non-energy deferral accounts.

The Board also notes that DERS indicated that the 2004 non-energy deferral account balances should be final by March 1, 2005 and that following that date, DERS proposed to file an application with the Board for approval of the final disposition of the accrued balance in each 2004 deferral account. The Board notes that DERS acknowledged during the hearing that they had not yet looked specifically at the reconciliation methodology. The Board directs DERS to submit its reconciliation filing by May 1, 2005 and to include a detailed description of its reconciliation methodology and a proposal for dealing with any balances.

### General Deferral Account Concerns

The Board notes that the Consumer Group was concerned that the flow-through of certain controllable costs would result in a lack of incentive on the part of DERS to effectively manage these costs and that customer care costs were of particular concern.

The Board notes the Consumer Group's submission that any deferral account opening balances taken over by DERS from ATCO should be subject to audit verification in order to avoid subsequent questions concerning the accuracy of amounts. The Board also notes the Consumer Group's submission that DERS should be directed to provide detailed formulas showing how the amounts transferred to or from the various energy and non-energy deferral accounts will be calculated. The Board agrees with the Consumer Group's submissions and notes that, in the Retail Sale Decision 2003-098, the Board directed that ATCO provide a report to the Board and interested parties, verified by an auditor, within six months of the close of the Retail Sale.

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[139] Exhibit 002-02, BR-DERS-7

The Board does not agree with the Consumer Group's statement that the details of amounts reflected in deferral accounts should be subject to review and confirmation by DEML's external auditors, however the Board expects DERS to be in compliance with Board precedents for calculation of gas and energy deferral accounts which could be audited by the Board at anytime.

The Board notes the Consumer Group's submission that any interest on deferral accounts should be subject to the guidelines provided in IL 2000-01. The Board does not consider that the application of interest to monthly balances of the non-energy deferral accounts is appropriate, because the Board does not expect the monthly balances in these accounts will be significant and the Board also expects that the balances in some months would be beneficial to customers and in other months would be detrimental to customers. The Board also notes that prior to the implementation of the monthly GCRR, ATCO Gas did not apply interest to the monthly DGA balances within a given season and these monthly balances were probably significantly larger than the monthly balances expected in the DRT and RRT non-energy deferral accounts. The Board will consider the use of IL 2000-1 when reviewing the disposition application for the non-energy RRT and DRT deferral accounts.

## 5 ELECTRIC AND GAS TERMS AND CONDITIONS

In the Application, DERS filed proposed Terms and Conditions of Gas Default Rate Service (DRS T&C) and Terms and Conditions of Electric Regulated Rate Service (RRS T&C) (jointly, the T&C). DERS noted that its proposed T&C were largely based on the Terms and Conditions of Regulated Rate Service approved for EPCOR Energy Services (Alberta) Inc. (EESAI). This section will deal with both the DRS T&C and the RRS T&C. In many cases, while parties may have referenced either the RRS T&C or the DRS T&C, they intended that their comments would apply to both. Unless the terms are different between the RRS T&C and the DRS T&C, the Board considers that the submissions apply to both.

### Views of the Interveners

### ATCO

With respect to section 9.4, ATCO disagreed with HVAC that customers of DERS should not be obligated to provide indemnification for and in respect of any loss that DERS sustains for the customer failing to comply with the ATCO Gas distribution tariff. ATCO argued that pursuant to ATCO's distribution tariffs, DERS was obligated, like all competitive retailers, to collect distribution tariff amounts on behalf of ATCO and it was required to compensate ATCO regardless of whether the end use customer pays their bill. Therefore, ATCO submitted that the indemnity provision was both necessary and appropriate.

### AUMA

AUMA submitted that a number of provisions in both the DRS T&C and the RRS T&C of DERS either unduly limit the rights of customers or give unnecessarily broad and unfettered discretion to DERS. Since these provisions are virtually identical between the RRT T&C and the DRT T&C, all submissions by the AUMA pertaining to the T&Cs will be handled in this section. AUMA submitted that where it is simple and sensible to add certainty to a specific T&C, it serves to reduce administrative problems and customer complaints in the future.

AUMA noted that although DERS committed to being reasonable in the application of the T&C,[140] customers should not have to totally rely on the actions of DERS if the T&C are either unreasonably restrictive on customers or allow too much unnecessary discretion to DERS as the regulated service provider.

### Article 5: Financial Security Requirements

**Section 5.1** of the T&C sets out the conditions under which DERS may require a deposit from a customer. Section 5.1 (b) notes that a deposit will be required if a customer has paid a bill late more than once in any four-month period. AUMA submitted that section 5.1(b) should be removed because paying a bill late twice in four months was hardly reason to demand a significant deposit, especially when the customer has paid the arrears and related interest.

**Section 5.3** of the T&C deals with the maximum deposit that customers will have to provide. The maximum deposit is defined as being equal to 33% of the annual total charge payable by the customer, as reasonably estimated by DERS. AUMA submitted that 33% of estimated annual consumption was excessive for the maximum deposit amount that DERS can require from customers and argued that 20% was a more appropriate amount. AUMA noted that, although DERS states that the 33% security deposit will not be triggered automatically if a customer misses two payment dates, section 5.1(b) allows DERS the discretion to demand it from customers.

**Section 5.5** of the T&C deals with the return of Deposits. Section 5.5 states that:

> … a Customer's deposit will be returned when the Customer's Default Rate Service is terminated and the Customer's account is closed. A Customer's deposit may be returned to the Customer after a satisfactory payment history over a period of 12 consecutive months.

AUMA noted that DERS will not be required to return a customer's deposit despite the fact that the customer has a satisfactory 12-month payment history. AUMA submitted that the word "may" should be replaced with "shall". AUMA argued that this still leaves DERS some discretion over being "satisfied" with the payment history over a period of 12 consecutive months.

### Article 8: Billings and Payment

**Section 8.7** of the T&C deals with other occupants' liability for payment. The proposed section 8.7 states:

> Where the Customer of Record for a Site has vacated the premises where the Site is located or defaulted on payment of a bill for Default Rate Service, other occupants of the premises who continue to receive Default Rate Service shall be deemed to be the Customer of Record and shall be liable for payment for Default Rate Service provided in accordance with the Default Rate Tariff.

AUMA submitted that the provision to make "other occupants" liable should be removed from section 8.7.

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[140] Tr., p. 512

### Article 9: Responsibility and Liability

**Section 9.3** of the T&C deals with the limitation of DERS's liability to customers. Section 9.3 limits the liability of DERS to direct physical damage, loss or injury to a customer of a customer's property resulting from the negligence or willful misconduct of DERS or its employees, agents or contractors acting within the scope of their employment. **Section 9.5** of the T&C deals with indemnification by DERS of customers and limits the indemnification by DERS in a similar manner as is done to its liability in section 9.3. **Section 9.4** of the T&C is the clause that describes the indemnification by customers.

AUMA submitted that sections 9.3 and 9.5 preclude customers from advancing any claims for "punitive or exemplary" damages against DERS regardless of its conduct. AUMA noted that punitive or exemplary damages are awarded to punish a defendant for "violent, oppressive, malicious, fraudulent or wanton and wicked conduct. AUMA argued that the words "exemplary" and "punitive" should be removed from these sections. Alternatively, and second best, AUMA submitted that section 9.4, which deals with the indemnification by customers, must be reworded to make it reciprocal to ensure that a customer shall not be liable to DERS/DEML for any "exemplary or punitive" damages.

Also with respect to sections 9.3 and 9.5, AUMA noted that DERS proposed to limit to 180 days, the time period for a customer to claim against it, even though the statutory limitation period is two years.[141] AUMA submitted that 180 days is not sufficient time for a customer to determine, assess and verify a claim and that it leaves inadequate time to attempt to informally resolve the claim. AUMA argued that the second paragraph in these sections should be removed.

AUMA noted that section 9.4 requires each customer to indemnify DERS for all legal fees on a solicitor-and-his-own-client basis if DERS pursued the customer for a claim under the T&C and argued that section 9.5 should be reciprocal and amended to give the customer the right to his legal fees on a solicitor-and-his-own-client basis if the customer pursued a claim against DERS.

AUMA submitted that although DERS is referenced as an entity through the T&C, the real legal entity behind DERS was DEML. AUMA argued that any liability or benefit under the T&C rests with DEML. AUMA submitted that the T&C could potentially and unknowingly limit the customer's rights against DEML where the customer also has a separate contractual unregulated relationship with DEML through one of DEML's various divisions. AUMA argued that if DEML were required to set up a separate legal entity like DERS Ltd. the potential legal problem would be removed.

AUMA agreed with DERS that consumer representatives can work with DERS to implement appropriate changes to the T&C but submitted that the methodology to implement changes (i.e. by committee outside of the regulated forum) and the timing of implementation make the proposal difficult to accomplish in practice. AUMA submitted that this approach has some merit and perhaps DERS can solicit comments on improvements to the T&C prior to the filing of its next rate application and that these comment could be incorporated in the respective DRT and RRT filings.

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[141] Section 3(1)(a) *Limitations Act*, R.S.A. 2000, c. L-12

### CCA

With respect to interest on security deposits, CCA noted the DERS proposal to pay interest on deposits at the greater of 2.5% or the interest rate specified under the *Residential Tenancies Act*. The CCA noted that rental deposits held under the *Residential Tenancies Act* must be held in a trust account.[142] CCA stated that utility security deposits were riskier because they are not held in trust. CCA submitted that, with the movement of security deposits from ATCO to DERS, customers face more risks, as distribution assets and the significant equity of the distribution company no longer support security deposits. CCA further submitted that with DERS's proposed corporate structure, security deposits will be exposed to the risks of unregulated activities.

CCA noted its preference to have the regulated activities of DERS in a separate corporation to protect customers and customer deposits. In addition, CCA suggested the following:

- DERS should be required to have equity and letters of guarantee to protect security deposits;
- the interest rate payable to customers should be greater than 2.5% and equal to the rate sought by DERS on necessary working capital;
- rather than having all customers receive the benefit of low cost financing, customers who pay the security deposit should benefit from the effect of the money being available to offset the necessary working capital costs of all customers; and
- DERS should be directed to provide quarterly filings of security deposit levels and explain any changes to the relative level with each filing.

With respect to credit cards, CCA noted that ATCO currently accepts credit cards under certain conditions and that DERS indicated that this is something they were considering.[143] CCA argued that DERS should be directed to ensure that customers are able to use credit cards under certain conditions and at a minimum, credit cards should be utilized to ensure the minimization of service cut offs and to speed connections or reconnections. CCA also submitted that customers should not be charged a greater amount because they are using a credit card. CCA argued that DERS should consider the use of credit card payments because it would likely minimize bad debts.

### Consumer Group

The Consumer Group submitted that, the following sections required a comprehensive review to ensure that there was compliance with plain language drafting and that the relevant sections set up a framework fair to both customers and DERS. The Consumer Group argued that this must take into account that customers often are un-represented lay people and will not have the familiarity with the T&C, the resources or commercial expertise of the DERS personnel.

- Interruption of Default Rate Service
- Force Majeure
- Limitation of DERS's Liability to Customer

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[142] Section 41(1) Residential Tenancies Act

[143] Tr. p. 1243

- Indemnification by Customer
- Indemnification by DERS
- Resolution by DERS and Customers
- Resolution by DERS and Customers
- Resolution by a Third Party

The Consumer Group submitted that in order to provide a truly seamless transition to retail service, DERS's T&C should seek to emulate the existing terms and conditions of ATCO Electric and ATCO Gas to the greatest extent possible.

The Consumer Group did not agree with DERS that the proposed T&C were balanced between DERS and its customers. The Consumer Group argued that the T&C appear to provide excessive discretion to DERS. With respect to this discretion, the Consumer Group noted that DERS made it clear throughout this proceeding that it intends to administer its T&C in a reasonable manner and argued that if DERS intends a provision to be less harsh than it currently reads, there should be no problem using language that reflects DERS's actual intentions.

The Consumer Group proposed that a review and determination of the specific language in the sections of the T&C be conducted as part of the DERS refiling and argued that any review should ensure that regulated customers are as thoroughly protected through the T&C as DERS.

Rather than using a further hearing process to revise the T&C, the Consumer Group recommended that DERS undertake revisions through a collaborative process because this will help avoid further, unnecessary litigation or hearing time and demonstrate DERS's intention to conduct itself in a reasonable manner.

### Article 2: Definitions and Interpretations

With respect to the definitions of "Customer", "Gas", and "Customer of Record" in section 2.1, the Consumer Group was concerned that the definition should not rely on reference to legislation or other documentation not part of the T&C and argued that the definitions should reside in the T&C.

In addition, the Consumer Group argued that the definition of "Customer" should also be expanded to include what "customer of record" means.

The Consumer Group submitted that "Person" was defined too broadly and argued that instead, the "customer of record" should be used for improved clarity. The Consumer Group further submitted that the definition seems at odds with the limited liability aspect of corporate law by including an individual member thereof as within the corporation.

### Article 3: General Provisions

**Section 3.2** of the proposed T&C state that customers will be bound to the T&C and the approved rate schedules as a condition of service. With respect to section 3.2, the Consumer Group argued that "each customer" should only apply to each "Customer of Record."

**Section 3.4** of the proposed T&C sets out the manner in which DERS proposes to amend the T&C. The Consumer Group submitted that section 3.4 should contain reciprocal language to allow a customer or customer group to request amendments to the T&C.

### Article 4: Regulated Rate Service

**Section 4.1** of the proposed T&C deals with the requirements for obtaining gas default rate service and electric regulated rate service. With respect to section 4.1, the Consumer Group submitted that definitions should not rely on reference to legislation or other documentation that are not part of the T&C. In addition, Consumer Group submitted that DERS should only require identification if it can reasonably support the request and that the types of identification required should not be excessive. The Consumer Group also submitted that DERS should open an account in a number of days set in accordance with best industry practices consistent with quality of service standards for Natural Gas or Electric utility service providers in Alberta as set or approved by the EUB. The Consumer Group argued that initial account opening should be done over the phone or in the time frame of the original call. The Consumer Group was concerned that "customer of record" was not finite and that an occupant may be deemed to be a customer or customer of record. The liability of other occupants as proposed in section 8.7 was noted as a concern. This concern also extends to the section dealing with Refusal of Default Rate Service (4.2).

**Section 4.3** of the proposed T&C sets out the credit information that DERS may require from customers. With respect to section 4.3, the Consumer Group submitted that this provision would allow DERS to obtain more information than required and argued that while creditworthiness was still an issue, it can be remedied if poor credit risk was balanced with a reasonable security deposit on fair terms.

**Section 4.4** sets out the provisions that DERS may apply if a customer fails to provide the credit information requested in section 4.3. With respect to section 4.4, the Consumer Group viewed this as too severe because it would allow cutoff of an existing customer simply for failure to provide information.

### Article 5: Financial Security Requirements

The Consumer Group stated that **section 5.1** was far too sweeping in its scope and argued that there should be a reasonableness test regarding when a deposit is required. The Consumer Group made the following comments and/or submissions:

- The demonstration of a satisfactory credit rating may place the least desirable customers, from a credit perspective, at a disadvantage.
    - Competitive retailers will be unwilling to take them as customers as they are a risk to the return and the regulated entity may refuse them as a credit risk.
- The regulated service recovers an allowance for bad debts and the provision of a reasonable security deposit may also mitigate this concern.
- The provision concerning late payment should be addressed by the imposition of penalty charges for late payment.
    - A more reasonable measure would be payments made more than 90 days after they are due as a basis for such additional information.

  - DERS will have adequate credit history for existing customers.
  - The extent of outstanding balances should be of more concern to DERS than potentially inadvertent late payments.
- The level of consumption between summer and winter may often equate to a 50% change in consumption patterns over previous periods, particularly for heat sensitive loads.
  - A more reasonable measure would be a 50% change in consumption when compared to that customer of record's consumption pattern over the same period in the previous year and the location of the customer of record has not changed.

**Section 5.2** of the proposed T&C gives DERS the sole discretion to wave the requirement for a security deposit by a customer. The Consumer Group submitted that DERS should provide sample terms indicating the criteria that it will consider in applying the discretion allowed in section 5.2.

With respect to **section 5.3**, the Consumer Group recommended that the section be expanded to include a reference price to estimate the total annual charge.[144]

**Section 5.4** of the proposed T&C allows DERS to apply a customer's deposit against any unpaid bills. With respect to section 5.4, the Consumer Group submitted that a deposit should be applied to the customer of record and used to pay any amounts owing by that customer of record and that the deposit should be paid in a fashion that would minimize late charges and other penalties. The Consumer Group argued that this section should only be available when an account and customer of record are being terminated and should not apply if a customer of record in arrears is transferring the account to a new location, unless the relocation results in the customer of record terminating service.

With respect to **section 5.5**, the Consumer Group submitted that "Satisfactory payment history" should be expanded on and should have clear parameters. In addition, the Consumer Group argued that the words "may be returned" should be amended to "will be returned".

### Article 6: Closing an Account

**Section 6.1** of the proposed T&C requires that customers provide at least three full business days to close an account. The Consumer Group submitted that customers should be allowed to close an account with any reasonable notification from the customer to DERS.

**Section 6.2** of the proposed T&C describes a customer's responsibility for payment. It states:

> The Customer is responsible for payment for all Regulated Rate Service provided to the Customer up to the time Direct Energy RS has closed the account and, until payment for final charges for consumption has been made.
>
> If a Customer's Regulated Rate Service is discontinued by Direct Energy RS or disconnected under the ATCO Terms and Conditions, the Customer is responsible for payment for all Regulated Rate Service provided to the Customer up to the time of such

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[144] The Consumer Group noted that for the DRT Terms and Conditions, the average of the monthly prices in the forward strip price for the next 12 months could be used. For the RRT Terms and Conditions, forward market information as required in Decision 2002 – 106, p. 37 could also be used.

> discontinuation or disconnection, and until payment for final charges for consumption has been made.

The Consumer Group was concerned that the first paragraph of section 6.2 may potentially allow accounts to languish in an open state after verbal notice has been served on DERS by the customer and that customer could then become responsible for ongoing fixed charges even though that customer wishes the account closed and has expressed this desire to DERS.

### Article 7: Measurement of Energy Consumption

**Section 7.1** of the proposed T&C notes that ATCO Electric/ATCO Gas provide meter reading and estimates of meter consumption for customers to DERS. DERS will base its billings on these meter readings and estimates. Also, DERS assumes no liability to the customer for the meter readings and estimates provided by ATCO Electric and ATCO Gas. The Consumer Group submitted that DERS was in the best position to assist the customer in understanding if a meter read or estimate appears to be in error. The Consumer Group stated that, as delegate of the distribution owner, DERS should include a nominal duty to assist customers in their dealings with the distribution company. The Consumer Group argued that this would be one instance where the expertise of DERS should be utilized to assist customers by the allowance of some discretion which may also serve to reduce the potential for complaint escalation. The Consumer Group further argued that, in seeking increases in the revenue requirement to address increased call volumes, including re-directs, DERS should undertake some responsibility for assisting customers and that such assistance should not be simply limited to the passing off of the customer to ATCO.

**Section 7.2** states that:

> If a Customer believes his or her meter to be in error, Direct Energy RS will arrange to have the meter tested by ATCO Electric at the request of the Customer and the Customer will pay Direct Energy RS all charges for meter testing incurred by Direct Energy RS in accordance with the ATCO Terms and Conditions.

The equivalent section referring to ATCO Gas is in the DRS T&C. With respect to section 7.2, the Consumer Group submitted that meters found to be in error should not result in costs or charges to the customer and that, if a meter was found to be in error, DERS should bear any costs or, more appropriately, should recover those costs from ATCO.

### Article 8: Billings and Payment

**Section 8.1** of the proposed T&C describes a customer's responsibility to pay his or her bill. With respect to section 8.1, the Consumer Group stated that "A bill delivered or mailed…" would be preferable to "A bill issued…".

**Section 8.2** of the proposed T&C defines late payment charges. The Consumer Group noted that the 5% used in this calculation was reduced by DERS and that the change was noted on the record of the proceeding.

**Section 8.3** deals with charges disputed by a customer. Section 8.3 states:

> The Customer has a right to dispute any charge in a bill. When a Customer disputes a bill, the Customer is still required to pay the bill in full by the due date. Direct Energy RS will review the disputed bill and make any adjustments and refunds that are warranted.

The Consumer Group submitted that customers should be allowed to pay an estimated or averaged amount for a bill under protest because this would give some symmetry to the rights of customers relative to DERS and demonstrate good faith on the part of both parties.

**Section 8.4** of the proposed T&C sets out the remedies for non-payment. With respect to section 8.4, the Consumer Group submitted that the increase to any deposit must be reasonable and within the scope of deposits, overall, as set out in the appropriate section of the T&C. In addition, the Consumer Group argued that some limitation on what constitutes a late payment should also be included. The Consumer Group submitted that the use of the word *person* (as it is currently defined) may expand collection to targets beyond what is common in commercial transactions of a similar nature.

**Section 8.5** describes what a customer must do to restore the provision of default rate service or regulated rate service. The Consumer Group submitted that section 8.5 was too broad because disconnection for any reason casts too wide a net. The Consumer Group argued that a reason, with cause, in the scope of the T&C would be more appropriate language. The Consumer Group submitted that disconnection may be the result of a customer moving to non-regulated service, moving out of the service area or simply moving to a location where service is provided by another customer of record (e.g. an apartment where utilities are provided as part of the rent). The Consumer Group argued that, if the customer wishes to later obtain or return to the default rate, the requirement for a deposit may serve as an artificial and unnecessary barrier.

**Section 8.6** states that partial payments on an account will be applied to the longest outstanding amounts on the bills. The Consumer Group submitted that more clarity or expanded explanation of section 8.6 was required and that a cross-reference to the use of deposits under section 5.4 was required.

With respect to **section 8.7**, the Consumer Group submitted that the section must relate only to customers of record and any deemed customers of record. The Consumer Group considered that the section would apply to customers in the latter group only after provision of notice to those customers that have been deemed customers of record. The Consumer Group argued that no party should be liable for bills prior to the time that the party is put on notice as being the customer of record. The Consumer Group submitted that this would also be contrary to the contractual principle of assignment because the rights and obligations of a contract cannot be assigned without notice to the parties affected and until notice was affected. The Consumer Group stated that, until notice was affected, the original parties to the contract would bear and benefit from its terms. In addition, the Consumer Group submitted that until notice was given to the new occupant and the contract for service was properly assigned, the new occupant would not be subject to the T&C.

**Section 8.8** states how dishonored cheques will be handled. **Section 8.9** states that DERS will refuse to accept payment when a customer attempts to make payment by a cheque drawn on a form other than a bank cheque. With respect to section 8.9, the Consumer Group submitted that reference to a third party document "Bank of Canada rules and regulations" should not be permitted in the T&C. The Consumer Group stated that DERS confirmed that it would apply to include amounts and denominations of currency required to be accepted by DERS. The Consumer Group argued that the maximum amounts and denominations of currency required to be accepted by DERS should be set out in plain English in the T&C and should be consistent with section 8 of the *Currency Act*, RSC Ch. C-52.

### Article 11: Miscellaneous

**Section 11.2** states that service under the DRT/RRT is not assignable. With respect to section 11.2, the Consumer Group argued that assignment of service was either required or, if not permitted, liability related to new occupants can only arise upon communicated commencement of service and then, only for services received after delivery of that notification.[145] The Consumer Group submitted that this provision may also be abused when the account was simply being updated to include or exclude another customer on the account. The Consumer Group argued that deposit and credit information requirements should not come into effect when the payment history prior to the addition or deletion did not trigger such requirements. The Consumer Group was concerned that this term may be taken to mean "service" generally was not assignable and that customers may be frustrated in thinking their service requirements are tied to DERS or another company under the DEML brand.

**Section 11.3** deals with the absence of a waiver of any of the terms or conditions included in the T&C unless the waiver is in writing and executed by an authorized officer of DERS. With respect to section 11.3, the Consumer Group submitted that since most customer contact will be conducted over the phone, the requirement for a waiver in writing seems overly excessive. In addition, the Consumer Group argued that since the contact to the call centre will be with ATCO I-Tek personnel, the language should be changed to reflect this fact.

With respect to the Price Schedule attached to the T&C, the Consumer Group submitted that the up-charges proposed by DERS for the Connection Charge and the Reconnection Charge in addition to ATCO charges and payable to DERS, should not be allowed. The Consumer Group stated that most of these services are covered by rates paid to ATCO and customers should not be further penalized.

### HVAC

HVAC noted that DERS was first to ever implement the DSP and regulated retail service functions, which are intended to be separate and apart from both the gas distribution and unregulated retail functions. HVAC submitted therefore that the Board should have careful regard to the question of whether ambiguous terms and conditions of service are found and the consequences that could arise if they are found. HVAC argued that avoiding the use of ambiguous terms would seem to be the easiest and most correct approach.

HVAC submitted that the Board should consider the following principles when assessing the Terms and Conditions:

- terms and conditions of service must be demonstrated by the applicant to be just and reasonable and therefore in the public interest;
- customers should find the terms and conditions to be clear, transparent and fair;

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[145] Consumer Group also referred to clause 8.7

- consideration must be given to whether the T&C may indirectly cause the promotion of switching from regulated to unregulated services; and
- consideration must be given to whether the use of ambiguous language could have unintended cost consequences to the regulated service that could be beneficial to those offering unregulated services.

### Article 8: Billings and Payment

With respect to Article 8, HVAC submitted that the heading "Billings and Payment" was a mischaracterization of the actual terms found under this section because the discussion only pertains to items related to payment. HVAC argued that billing, including the contents of the billing envelope, was an element of customer service that the Board has jurisdiction over and that it must be addressed in the Tariff given the requirement in section 5(1)(g)[146] of the *Electric RRR Regulation*. HVAC submitted that the Board has the responsibility and authority to ensure terms and conditions related to billing are included in the Tariff and are in an acceptable form from a customer perspective. HVAC argued that Article 8 should be revised to provide customers with a reasonable understanding of how the DSP intends to carry out its billing functions.

HVAC submitted that, in the alternative to outright disallowance of preferential billing envelope access, customer choice should dictate whether any materials in addition to the regulated retail service and gas distribution bill should be included in the billing envelope and received by a customer. HVAC argued that if retail deregulation was about providing customer choice, it would be entirely consistent to require DERS to include in its tariff a condition which first obligates each customer to provide written consent to receipt of information wholly unrelated to the supply of default regulated service or service respecting the gas distribution function. HVAC submitted that this would ensure that unintended and inappropriate links are not created in the minds of customers as between DERS and/or ATCO Gas and any unregulated affiliate engaged in the energy and related energy services business.

HVAC submitted that DERS should adopt the principle of providing customers with express and informed consent based on the fundamental principle applicable to a trustee whereby the trustee must act selflessly in the best interest of the beneficiary (i.e. customers in this case). In this case, HVAC submitted that the duty of DERS to obtain informed consent from customers arises given that DERS intended to allow use of and access to the customer's billing envelope for purposes that go beyond the provision of regulated services. HVAC argued that at common law, a beneficiary must consent to a use of trust property – in this case customer information – where that use was beyond the scope of the trustee's mandate.

### Article 9: Responsibility and Liability

**Section 9.2** of the proposed T&C deals with force majeure. HVAC submitted that it was informed, through cross-examination, of DERS's intention to have the force majeure limits of section 9.2 apply not only to the affairs of DERS, the business unit, but to all of DEML. HVAC submitted that since DERS is the only business unit referenced in the Tariff, customers entering into this agreement would not know that other business units will in fact be providing services to DERS related to the services to be provided under and pursuant to the Tariff.

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[146] HVAC submitted that section 5(1)(g) of the Electric RRR Regulation requires a default supply provider to carry out billing pursuant to a default rate tariff approved by the Board.

HVAC argued that the resulting risk created by the current language of section 9.2 was that customers may very well be able to sue and recover from DEML in respect of its other business units, notwithstanding that such a loss was in connection to the provision of Default Regulated Service. If such losses were realized, HVAC submitted that it was a result of the organizational structure that DERS has voluntarily assumed and the choice of language that DERS has proposed in this Tariff. HVAC submitted that higher regulated service costs arising due to the choice of ambiguous tariff language ought not to unintentionally or otherwise be used or appear to be used as a means of promoting price advantages in the unregulated services marketplace.

With respect to **section 9.3**, HVAC submitted that the choice of language found in this section implies that DERS has employees. HVAC submitted that only DERS or its employees are subject to limited liability. Actions arising against DEML employees or officers and directors of DEML who provide services to DERS are not expressly excluded. HVAC submitted that, although DEML was the only employer and not DERS, that fact was in no way explained to the customer. HVAC considered that, based on the wording, it would be reasonable for a customer to reach a completely opposite conclusion. HVAC submitted that the organizational structure and language chosen by DERS is again the source of this confusion and potential legal risk. HVAC argued that, should tariff ambiguity give rise to monetary losses, regulated service ratepayers should not bear cost responsibility. HVAC submitted that DERS should be made aware of this fact from the outset so that there is no misunderstanding or issue at some future time.

With respect to **section 9.4**, HVAC understood that DERS was seeking indemnification from customers for and in respect of any loss that DERS sustains for the customer failing to comply with the ATCO Gas Distribution Tariff. HVAC saw no reason why customers of DERS should be obligated to provide such an indemnity to DERS and argued that it was up to ATCO Gas Distribution and not DERS to seek appropriate indemnities through its Tariff, as well as exclusions from liabilities in respect of service ATCO provided to customers.

### Views of DERS

DERS stated that its proposed T&C were developed using two fundamental principles:

- consideration of existing utility terms and conditions in order to provide consumers with some degree of similarity; and
- to establish a reasonable balance between the interests of individual consumers with the balance of consumers taking regulated service.

DERS indicated that its T&C were written in a manner as permissive as possible, to allow the Company flexibility to address specific circumstances. DERS also indicated that it will administer its T&C in a reasonable manner.

DERS submitted that the T&C were intended to provide operating parameters within which DERS will interact with customers. DERS argued that the charges contained in the Price Schedule are reasonable and balanced and for the most part simply reflect the pass through of charges, if any, from the distributor.

DERS encouraged consumer representatives to work with DERS to implement appropriate changes to the T&C and noted that consumers can always petition the Board if they believe that DERS is being unresponsive.

DERS did not agree with the Consumer Group assertion that the T&C were designed to force customers to unregulated services in order to achieve DEML's business objectives. DERS argued that the T&C should not be amended because nowhere in the T&C does it state that any customer can or will be transferred from regulated to unregulated service.

DERS agreed with the Consumer Group suggestion that DERS should indicate on its bills that its terms and conditions were available on the website or by contacting DERS.

DERS did not agree with the AUMA suggestion that section 5.1(b) of the T&C be removed because this section intends to administer the terms and conditions in a reasonable manner and is for the benefit of the balance of customers served by DERS.

With respect to the AUMA suggestion that the maximum deposit under section 5.3 should be reduced to 20% from 33% of the total annual bill, DERS submitted that the 33% was valid. The ATCO T&C include a maximum deposit of 30% of the total annual bill. DERS stated that it was appropriate for DERS to charge a higher maximum deposit than ATCO. DERS noted that, since the wire service provider does not collect the money for a bill, it is not out-of-pocket for the full amount of all of the components in the distribution tariff. DERS stated that, as the retailer, it takes the full risk of the bad debts on behalf of the wire service provider and will be paying the wire service provider's distribution tariff regardless of whether or not the customer pays the bill.

DERS did not agree with AUMA's suggestion that the word "may" in section 5.5 be replaced with the word "shall" because retention of the word "may" would allow for the earlier return of a deposit and also allow for the retention of the deposit in situations described in section 5.1(d).

DERS noted that it proposed to add an explicit reference to due dates in section 8.1.[147] Following input from customer representatives, DERS proposed to modify its late payment charge in Article 8.2 from a one-time 5% late payment penalty to an interest charge of 1.5% per month of the outstanding balance.

DERS did not agree with AUMA's suggestion that deeming other occupants to be the customers of record should be removed from section 8.7. DERS submitted that the retention of the deemed customer of record provision in this section protected other customers from having to inordinately bear the cost of arrears and was intended to ensure that individuals availing themselves of regulated service are obligated to pay for that service.

DERS agreed with the Consumer Group suggestion that section 8.9 of the terms and conditions be amended to reflect the *Currency Act*, RSC Ch. C-52.[148]

With respect to AUMA's suggestion that the words "exemplary" and "punitive" be removed from sections 9.3 and 9.5, DERS submitted that the sections should remain as they are, to the extent that they provide the required balance between the interests of individual customers and all other customers served by DERS.[149]

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[147] This change was in response to an undertaking given to Mr. MacDonald at Tr. p. 1447

[148] Consumer Group Written Argument, p. 66

With respect to AUMA's suggestion that the second paragraph in sections 9.3 and 9.5 be removed, DERS submitted that the 180 day period in which customers must file any claims against DERS was an appropriate and reasonable period of time.

DERS noted AUMA's suggestion that section 9.5 should be amended to provide reciprocity for legal costs[150]. DERS has proposed to remove its entitlement to solicitor/client costs as currently included in section 9.4 of the T&C.

In response to the Consumer Group, DERS stated that it will respond to selected suggestions and comments. The balance of the Consumer Group's suggestions regarding specific adjustments to terms and conditions, have been dealt with in aggregate through the comments of DERS. DERS submitted that these suggestions be disregarded in total.

DERS did not agree with Consumer Group's suggestion that all of the charges contained in DERS's price schedule appended to the terms and conditions be disallowed because this would serve only to benefit individual customers at the expense of the balance of regulated customers served by DERS.

DERS did not object to CCA's suggestion that DERS be directed to accept credit card payments under certain conditions and to consider the use of credit cards for all payments. DERS noted that there would be an increase to DERS's revenue requirements associated with the acceptance of credit card payments. DERS assumed that CCA would expect appropriate cost causation principles to apply to this cost.

With respect to the HVAC's comment on section 9.2, DERS indicated that all provisions respecting responsibility and liability would apply in respect of DEML. With respect to the question of who a party would sue in the event of a claim arising out of the business activities of DERS, DERS indicated that the party would sue DEML, carrying on business as DERS.

### Views of the Board

The Board notes the suggestion made by some parties, and agreed to by DERS, that the T&C can be addressed in greater detail through a negotiated process between DERS and customer group representatives. The Board agrees that this is often a more efficient means to deal with the issues that arise in the T&C, rather than through a hearing process. However, the Board notes that due to the timing of this proceeding and the desire of DERS to commence operation as the supplier of DRT and RRT service as soon as possible, it is necessary that T&C be in place for the commencement of operations by DERS. The Board considers that future proposed T&C would benefit from some form of consultative process between DERS and customer representatives. The Board expects that such a process would take place prior to or in conjunction with the next DERS rate application.

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[149] Written Argument of DERS, p. 50

[150] AUMA/CE Written Argument, p. 48

The Board will direct DERS to refile its T&C incorporating both the changes directed by the Board in this section and any changes that DERS agreed to make to the T&C during the course of the proceeding.

The Board is addressing only certain changes proposed by Interveners to the T&C at this time. These include those sections that the Board considers should be changed immediately. The Board considers that other changes are best left until negotiations between customer representatives and DERS can take place. The Board is also commenting on some further sections where it does not consider that changes are necessary at this time.

**Section 3.4** deals with regulatory approval and amendment. The Board considers that only minor wording changes can be made to the T&C by way of DERS filing a notice of amendment with the Board. The Board considers that, as with any rate or charge, the T&C make up the rate tariffs that are approved by the Board and therefore that any changes to the T&C require Board approval. The Board notes that minor wording changes or corrections are generally exempt from the typical approval process in the interest of minimizing processes for minor matters. However, the Board notes that DERS is still required to file any such minor changes with the Board as a filing for acknowledgement. At that time, the Board can determine whether or not the proposed changes fit the Board's expectation of a minor change and in the event that they do not, will direct DERS to request approval for the changes through a more formal process. The Board directs that section 3.4 be revised to more closely reflect the Board's expectation on changes to the T&C.

In more than one instance, including **section 4.1**, the Consumer Group stated that DERS should not reference other legislation or documentation that is not part of the T&C. The Board notes that T&C that are self-contained would make the document easier for customers to use. However, the Board notes the difficulty in incorporating all of the references without making the document unnecessarily long and complex. The Board considers that the appropriate balance between these concerns is one of the matters that could most appropriately be dealt with in a negotiated process between DERS and customer representatives. However, by way of guidance the Board would expect that key terms or frequently appearing terms would be defined in the T&C and that definitions would not be incorporated by reference from other sources.

With respect to **section 4.3,** which sets out the requirement for a customer to provide credit information, the Board considers it reasonable that DERS be able to receive credit information from a customer. The Board notes however that, as a regulated service provider, DERS has an obligation to provide service to customers. The Board notes that, in the circumstance where a customer either cannot provide a credit history or does not have a good credit history, a customer can obtain service by providing an appropriate deposit. Therefore the Board considers that the conditions set out in **section 4.4** are overly restrictive. DERS should not have the ability to deny service to a customer who is unable or unwilling to provide credit information to DERS if that customer is prepared to provide a security deposit. Therefore the Board directs that section 4.4 should be revised as follows:

> 4.4 Failure to Provide Information Service
> If a prospective Customer or existing Customer fails to provide information requested in accordance with Section 4.3 **and does not provide a security deposit in accordance with Article 5**, then Direct Energy RS may either:
> (a) refuse to provide Regulated Rate Service to the prospective Customer, or

> (b) discontinue or request a disconnection of Regulated Rate Service to the existing Customer.

The revised wording added by the Board is bolded and underlined in the above section.

**Section 5.3** of the T&C proposes that the maximum deposit that DERS will require from a customer be set at 33% of the estimated annual total charge payable by a customer. The AUMA/CE recommended that the maximum deposit be reduced from 33% to 20%. The Board notes that both ATCO Gas and ATCO Electric currently set the maximum deposit at 30% of the estimated annual bill. The Board considers that there is no reason to increase the maximum deposit above the level that is currently used by the ATCO service providers. Therefore the Board directs DERS to revise section 5.3 so that the maximum deposit is reduced from 33% to 30% of the "annual total charge payable."

**Section 5.5** of the T&C deals with the circumstances under which a customer's deposit will be returned. DERS has proposed that it shall be left to its discretion whether or not a deposit is returned after 12 consecutive months of satisfactory payment history. Both AUMA and the Consumer Group recommended that DERS be required to return a customer's deposit after 12 consecutive months of satisfactory payment history. The Board considers that it is appropriate that DERS be allowed some discretion in determining when a customer's deposit will be returned. However, the Board considers that the current wording proposed by DERS is too open ended and uncertain to provide the customer with a reasonable amount of assurance. The Board therefore directs that section 5.5 of the T&C be amended as follows:

> 5.5 Return of Deposit
> Subject to Section 5.4, a Customer's deposit will be returned when the Customer's Regulated Rate Service is terminated and the Customer's account is closed. A Customer's deposit may be returned to the Customer after a satisfactory payment history over a period of 12 consecutive months **but no later than a period of 18 consecutive months of satisfactory payment history**.

With respect to **section 7.1** of the proposed T&C, the Consumer Group stated that it was inappropriate for DERS to not assume any liability to the customer for meter readings and estimates provided by ATCO Gas and/or ATCO Electric. The Consumer Group stated that DERS was best positioned to assist customers in their dealings with the distribution company. The Board agrees with the Consumer Group that DERS should be able to assist customers in their dealings with the distribution companies. However, the Board considers that section 7.1 does not preclude this from happening.

**Section 7.2** of the proposed T&C deals with meter testing and states that a customer will pay all charges for meter testing incurred by DERS in accordance with the ATCO T&C. The Board notes that the ATCO Electric Wires T&C (section 10.4(c)) states that ATCO "reserves the right to assess a charge to the Retailer for a meter test, in circumstances where the Company has not been responsible for any metering error…" The Board considers that the combination of the two sections, section 7.2 of the DERS T&C and section 10.4 of the ATCO Electric Wires T&C, maintains the same provisions as previously applied to customers. The Board considers that it is only appropriate for a customer to pay for meter testing if the customer requests the test and the meter is found to be properly functioning. The Board considers that the combination of the two T&C continues to follow this accepted practice.

**Section 8.3** states that a customer is required to pay a bill that is under dispute. The Consumer Group submitted that a customer should be allowed to pay an estimated or average bill. The Board has concerns with the inclusion of section 8.3 in the T&C. The Board notes that when a complaint is under investigation by Board staff, the standard practice is that the amount in dispute does not have to be paid until the dispute is resolved. Charges for prior and subsequent periods that are not disputed are expected to be paid by the customer. The Board considers that section 8.3 changes this accepted practice. The Board also notes that there have been instances where an error made on a customer's bill is at a level that is clearly unreasonable. For example, a residential customer who normally receives an electric bill in the range of $100, receives a bill for $10,000. The Board notes that under the wording in section 8.3, the customer would be expected to pay the $10,000 bill. This is clearly not acceptable. Therefore, the Board finds that for the sake of the Refiling, section 8.3 regarding Disputed Charges should be removed from the T&C. The Board considers that DERS may propose, at a future time, a revised clause concerning Disputed Charges that addresses the Board's concerns with the current proposed wording.

**Section 8.5** sets out the requirements that a customer must meet to have service restored. The Consumer Group argued that the wording of section 8.5 is too broad. The Board concurs that the current proposed wording in section 8.5 allows too much discretion on the part of DERS. The Board considers that the words "for any reason" could allow DERS to collect a deposit in circumstances where it is not warranted. The Board considers that the words "for any reason" should be replaced with "for non-payment". Therefore the Board directs[151] that section 8.5 be revised as follows:

> 8.5 Restoration of Regulated Rate Service
> In order for Regulated Rate Service to be restored after it has been discontinued or disconnected for **non-payment**, the Customer must pay all outstanding bills in full, provide a deposit to Direct Energy RS and pay the reconnection fee prescribed in the Price Schedule.

**Section 8.7** deals with the liability of other occupants for payment of an account. Concerns regarding this section were raised by both AUMA and the Consumer Group. The Consumer Group suggested that this section allows for the assignment of rights and obligations without notice to the affected parties. The Board shares the concerns of the Interveners. The Board is concerned that the language in the section is too general and could be very difficult to interpret in the case of a dispute. The Board notes that the section does not specify how other occupants will be identified, whether other occupants may be responsible for arrears on the account and the notice that must be provided to occupants to advise them that they are now the customers of record. The Board notes that it may be acceptable to make occupants responsible for an account on a going forward basis if proper notice is provided. However the Board finds that the proposed language is too vague and potentially problematic. The Board further considers that section 8.7 is contrary to the proposed section 11.2, which states that service under the DRT/RRT is not assignable. Therefore the Board directs DERS to remove section 8.7 from its refiling of the T&C. The Board considers that DERS can propose an alternative section at a future date dealing with the liability of other occupants that addresses the Board's concerns.

The Consumer Group recommended that the Connection Charge and the Reconnection Charge included in the DERS Price Schedule be amended to include only the charge from ATCO Gas or

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[151] The Board notes that the appropriate wording will be used with respect to the DRS T&C.

ATCO Electric. The Board notes that DERS is proposing to charge $10 plus any applicable ATCO charges for Connection Charges and $50 plus any applicable ATCO charges for Reconnection Charges. The Board notes that any costs incurred in connecting or reconnecting a customer are borne by the distribution company, and is unaware of the amount of additional costs that might be incurred by DERS. Consequently, the Board is not convinced that the proposed additional charges are reflective of the cost to DERS. The Board therefore directs DERS to amend the Price Schedule attached to the T&C by changing the $50 reconnection fee to $25. Therefore the Board will lower the amount proposed by DERS to be added on to the ATCO reconnection charges until such time as DERS can justify its charges. The connection charge will remain at the proposed $10 and the reconnection charge will be reduced from $50 to $25.

The Board directs DERS to refile its proposed DRS T&C and its proposed RRS T&C, incorporating all changes noted above, and any changes that DERS agreed to make to the T&C during the course of the proceeding, with the Board and registered Interveners no later than December 29, 2003. The Board will then confirm that the changes have been properly included in the refiled T&C and upon such confirmation will approve the refiled T&C.

## 6 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Amendments allow the Board to extend compliance with the new provisions by DERS until July 1, 2004. The Board notes that on December 8, 2003, DERS filed an application requesting that the Board grant an extension of the date for the implementation of a transition rate in the ATCO Electric service territory as contemplated in the Amendments to the *RDS Regulation*. The Board also notes that DERS indicated that if the Board granted the extension, it would immediately file for approval to enter into negotiated settlement discussions with interested parties on this matter. The Board in this Decision will grant the requested extension and in order to bring the terms and conditions of the RRT approved by this Decision into compliance with the *RDS Regulation* as amended, the Board directs DERS to file an application on or prior to February 15, 2004 if it appears that the settlement process will not be successful. Otherwise, DERS is directed to file its negotiated settlement application by March 31, 2004. .................................................. 6
2. The Board directs DERS to demonstrate at the time of its next DRT and RRT non-energy applications what its cost of providing working capital would be if it obtained its working capital through a financial institution, on a stand-alone basis with a parental guarantee. ....... 45
3. However, with respect to future assignment of the cost categories to energy and non-energy deferral accounts, the Board considers that there may be merit in restructuring the RRT deferral accounts. Therefore, the Board directs DERS to submit a study as part of its next non-energy RRT application that describes the implications of restructuring its RRT deferral accounts in a fashion similar to its DRT deferral accounts. .................................................. 67
4. Furthermore, the Board directs DERS to undertake a comprehensive benchmarking study to determine if the charges under the MS Agreement represent fair market value for the services provided and if not, what the fair market value is for the services. Once the Board has

completed its review of the benchmarking study, the Board will replace the placeholder for customer care costs based on fair market value. ............ 87

5. Nevertheless, the Board directs DERS to investigate the merits of these possible refinements of the allocation method at the time of its next DRT and RRT applications. ............ 110

6. The Board directs DERS to submit as part of its February 2004 GCFR filing a schedule outlining the final outcome of each Major Contract. ............ 116

7. However, in order to continue implementation of this pooling concept, the Board directs DERS to provide evidence in its next DRT application that demonstrates that neither the regulated or non-regulated entities are clearly benefiting from the process. ............ 116

8. Therefore, the Board directs DERS to include in its monthly GCFR filings, separate schedules that show the actual day gas purchases in the reconciliation month. In addition, the Board expects DERS to record its procurement protocol and activities in sufficient detail that would permit an audit that could be initiated by the Board at any time. ............ 116

9. Therefore, the Board directs DERS to demonstrate as part of its next DRT application that its use of the NGX and other gas counterparties is reasonable when considering overall costs and benefits to the regulated customers. ............ 117

10. However, in order to ensure that there is no misunderstanding, the Board directs DERS in its monthly GCFR filings to follow the format and level of detail provided by ATCO Gas, except for the additional day gas purchase schedules noted above, other schedules noted in this Decision and any other required differences that DERS can substantiate. ............ 117

11. While the Board will not require DERS to provide the level of credit required by contract, the Board directs DERS to include in its monthly GCFR filing a schedule that shows credit support expenses for three components: the NGX, contracts assigned by ATCO Gas, and other gas supply contracts. ............ 122

12. In order to provide clarity, the Board directs DERS to implement the following reconciliation procedures for the working capital, bad debt and penalty revenue in the DGA: ............ 135
    - Use the approved forecast revenue requirements and include a prorated monthly amount of this approved forecast in the monthly GCFR filings. ............ 135
    - In the March 2005 GCFR information package, provide a detailed reconciliation of the forecast and actual monthly amounts. ............ 135
    - Include any differences between the actual amount and forecast amount that was used to determine the monthly GCFRs in the test period, in the derivation of the March 2005 GCFR. ............ 135
    - If such reconciling amounts cause a difference of greater than 3% to the GCFR otherwise determined for March 2005, the adjustment should be applied reasonably over the remaining months of the then current calendar year in a manner acceptable to the Board. 135

13. The Board also directs DERS to implement the following reconciliation procedures for the credit charges and the other cost categories in the DGA: ............ 136
    - in the monthly GCFR filings, update forecast, estimated and actual numbers using the best available information. ............ 136

14. The Board also notes that DERS indicated that the 2004 non-energy deferral account balances should be final by March 1, 2005 and that following that date, DERS proposed to file an application with the Board for approval of the final disposition of the accrued balance

in each 2004 deferral account. The Board notes that DERS acknowledged during the hearing that they had not yet looked specifically at the reconciliation methodology. The Board directs DERS to submit its reconciliation filing by May 1, 2005 and to include a detailed description of its reconciliation methodology and a proposal for dealing with any balances. ................ 136

15. The Board directs DERS to refile its proposed DRS T&C and its proposed RRS T&C, incorporating all changes noted above, and any changes that DERS agreed to make to the T&C during the course of the proceeding, with the Board and registered Interveners no later than December 29, 2003. The Board will then confirm that the changes have been properly included in the refiled T&C and upon such confirmation will approve the refiled T&C..... 154

# 7 ORDER

IT IS HEREBY ORDERED THAT:

(1) Effective upon Direct Energy Regulated Services assuming the role of the Regulated Rate Tariff service provider, the Regulated Rate Tariff rates in Appendix 8 are approved and shall apply as Direct Energy Regulated Services's interim 2004 Regulated Rate Tariff non-energy rates.[152]

(2) In accordance with the amendments to the *RDS Regulation*, Direct Energy Regulated Services is hereby granted an extension until July 1, 2004 for the requirement to implement a transition rate for all eligible RRT customers.

(3) Effective upon Direct Energy Regulated Services assuming the role of the Regulated Rate Tariff service provider, Direct Energy Regulated Services is approved to provide a monthly "flow-through rate" for the energy cost component of the RRT until a transition rate is implemented.

(4) Effective upon Direct Energy Regulated Services assuming the role of the Default Supply Provider, the Default Rate Tariff rates in Appendices 6 and 7 are approved and shall apply as Direct Energy Regulated Services's interim 2004 North and South Default Rate Tariff non-energy rates.[153]

(5) Effective upon Direct Energy Regulated Services assuming the role of the Default Supply Provider, Direct Energy Regulated Services is approved to provide a monthly "flow-through rate" for the energy cost component of the DRT, as prescribed by section 3(5) of the DGS Regulation, for the 2004 test period.

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[152] The spreadsheet used to calculate the RRT non-energy rates is included in Appendix 10.

[153] The spreadsheet used to calculate the DRT non-energy rates is included in Appendix 9.

Dated in Calgary, Alberta on December 18, 2003.

**ALBERTA ENERGY AND UTILITIES BOARD**

B. T. McManus, Q.C.
Presiding Member

J. I. Douglas, FCA
Member

W. K. Taylor
Acting Member

## APPENDIX 1 – PARTIES PARTICIPATING IN THE PROCEEDING

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| ATCO Electric Ltd. (ATCO Electric)<br>ATCO Gas North and ATCO Gas South (ATCO Gas)<br>L. Keough<br>K. Illsey | |
| Direct Energy Regulated Services (DERS)<br>K. Miller | *Revenue Requirement and Rate Design Panel:*<br>G. Newcombe<br>R. Hemstock<br>J. Gauthier<br>J. Pataky<br>A. Kumar<br><br>*Parental Guarantee Costs Panel:*<br>W. Foster<br>D. Halwas<br>R. Hemstock<br>A. Le Poidevin<br><br>*Customer Care Panel:*<br>M. Chwalowski<br>G. Newcombe<br>L. Dewar Laurie<br>T. Kozak<br>J. Milne |
| Alberta Urban Municipalities Association and City of Edmonton (AUMA/CE)<br>R. McCreary | |
| City of Edmonton (Edmonton)<br>B. Follett | |
| Public Institutional Consumers of Alberta (PICA)<br>N. McKenzie | |
| Federation of Alberta Co-ops Ltd. and Gas Alberta Inc., Alberta Association of Municipal Districts and Counties, Alberta Rural Utilities Association, Prairie Power Ltd., Alberta Federation of REAs (Federation)<br>T. Marriott<br>D. Jenkins | |

| Principals and Representatives (Abbreviations Used in Report) | Witnesses |
|---|---|
| Alberta Federation of REAs (REAs)<br>K. Sisson | |
| City of Calgary (Calgary)<br>R. Meronek<br>K. Saxberg | *Customer Care Panel:*<br>J. Stephens<br>F. Gogel<br>*City of Calgary Panel:*<br>H. Vander Veen<br>K. Sharp<br>G. Matwichuk |
| Lennox Inc., Heating Refrigeration and Air Condition Institute of Canada, Mechanical Contractors Association of Alberta, Sheet Metal Contractors Association of Alberta (HVAC)<br>J. Smellie<br>G. Nettleton | |
| Consumers Coalition of Alberta (CCA)<br>J. Wachowich | |
| Aboriginal Communities and St. Michael's Extended Care Society (Ab-Com)<br>A. O. Ackroyd<br>R. Bellows | |
| Alberta Irrigation Projects Association (AIPA)<br>H. Unryn | |
| AltaGas Utilities Inc. (AltaGas)<br>R. Koizumi | |
| Board Panel<br>B. T. McManus, Q.C., Presiding Member<br>J. I. Douglas, FCA<br>W. K. Taylor, Acting Member | |
| Board Staff<br>B. McNulty, Board Counsel<br>M. Hagan<br>W. Vienneau<br>D. R. Weir<br>C. Burt | |

## APPENDIX 2 – ABBREVIATIONS

| | |
|---|---|
| Asset Sale Transactions | Electricity Assets Transfer Agreement and the Gas Assets Transfer Agreement |
| AltaLink | AltaLink Management Ltd |
| ATCO | ATCO Electric and ATCO Gas |
| ATCO Electric | ATCO Electric Ltd. |
| ATCO Gas | ATCO Gas North and ATCO Gas South |
| Board or EUB | Alberta Energy and Utilities Board |
| CIS | Customer Information System |
| *Code of Conduct Regulations* | *Code of Conduct Regulation*, AR 160/2003 under the *Electric Utilities Act* and *Code of Conduct Regulation*, AR 183/2003 under the *Gas Utilities Act* |
| DEA | Deferred Electricity Account |
| *DEML* | Direct Energy Marketing Limited |
| DEP | Direct Energy Preferred |
| DERS | Direct Energy Regulated Services |
| DGA | Deferred Gas Account |
| *DGS Regulation* | *Default Gas Supply Regulation*, AR 184/2003 |
| *DRS T&C* | Terms and Conditions of Gas Default Rate Service |
| DRT | Default Rate Tariff |
| DSP | Default Supply Provider |
| *DT Regulation* | *Distribution Tariff Regulation*, AR 162/2003 |
| EATA | Electricity Assets Transfer Agreement |
| EESAI | EPCOR Energy Services (Alberta) Inc |
| *Electric Code Regulation* | *Code of Conduct Regulation*, AR 160/2003 under the *Electric Utilities Act* |
| *Electric RRR Regulation* | *Roles, Relationships and Responsibilities Regulation*, AR 169/2003 under the *Electric Utilities Act* |
| EUA | *Electric Utilities Act*, S.A. 2003, c. E-5.1 |
| FTE | Full Time Equivalent |
| FMV | Fair Market Value |
| *Gas Code Regulation* | *Code of Conduct Regulation*, AR 183/2003 under the *Gas Utilities Act* |
| *Gas RRR Regulation* | *Roles, Relationships and Responsibilities Regulation*, AR 186/2003 under the *Gas Utilities Act* |
| GATA | Gas Assets Transfer Agreement |
| GCFR | Gas Cost Flow-Through Rate |
| GCRR | Gas Cost Recovery Rate |
| GRA | General Rate Application |
| GTA | General Tariff Application |
| GUA | *Gas Utilities Act*, R.S.A. 2000, c. G-5 |
| IVR | Interactive Voice Response |
| MS Agreement | Master Service Agreement |
| NGX | Natural Gas Exchange |
| NWC | Necessary Working Capital |
| OEB | Ontario Energy Board |
| PBR | Performance Based Ratemaking |

| | |
|---|---|
| PIPEDA | Federal *Personal Information Protection and Electronic Documents Act* |
| PPFR | Pool Price Flow-Through Rate |
| PUB Act | *Public Utilities Board Act,* R.S.A. 2000, c. P-45 |
| *RDS Regulation* | *Regulated Default Supply Regulation*, AR 168/2003 |
| *RRO Regulation* | *Regulated Rate Option Regulation*, AR 45/2000 |
| RRP | Regulated Rate Provider |
| RRS T&C | Terms and Conditions of Electric Regulated Rate Service |
| RRT | Regulated Rate Tariff |
| Separation Cost Provisions | Section 5(1) of the *RDS Regulation*, section 5 of the *DT Regulation*, and section 10 of the *Natural Gas Billing Regulation* |
| T&C | jointly DRS T&C and RRS T&C |
| TransAlta | TransAlta Utilities Corporation |
| *UFE* | Unaccounted for Energy |
| UNCA | UtiliCorp Networks Canada (Alberta) Ltd. |

## APPENDIX 3 – RELATED DECISION REPORTS/PREVIOUS BOARD DECISIONS REFERENCED

| | |
|---|---|
| Decision 2000-88 | ATCO Electric Ltd.<br>Regulated Rate Option Tariff, Part B: Non Energy Cost Component<br>dated December 22, 2000 |
| Decision 2001-75 | GCRR Methodology and Gas Rate Unbundling<br>Part A: Methodology and Unbundling Proceeding<br>dated October 30, 2001 |
| Decision 2001-92 | 2000 Pool Price Deferral Accounts Proceeding<br>Part K: Recovery Period, Carrying Cost Rates, Collection Issues and Hedging<br>dated December 12, 2001 |
| Decision 2001-97 | ATCO Pipelines South<br>2001/2002 General Rate Application, Phase I<br>dated December 12, 2001 |
| Decision 2002-034 | ATCO Gas South<br>GCRR Methodology and Gas Rate Unbundling – Compliance Filing<br>dated March 21, 2002 |
| Decision 2002-085 | ATCO Electric Ltd.<br>2002 Regulated Rate Option Tariff, Part C: 2002 Rates<br>dated September 24, 2002 |
| Decision 2002-105 | ATCO Electric Ltd.<br>2003 Regulated Rate Option Tariff, Part B: Final 2002 and Interim 2003 RRO Non-Energy Rate<br>dated December 11, 2002 |
| Decision 2002-106 | ATCO Electric Ltd.<br>2003 Regulated Rate Option Tariff, Part A: 2003 Energy Rates<br>dated December 11, 2002 |
| Decision 2003-015 | ATCO Gas<br>Reconciliation Process for Certain Costs and Revenues Charged to the Gas Cost Recovery Rate and Company-Owned Storage Rate Rider<br>dated February 18, 2003 |
| Decision 2003-040 | ATCO Group<br>Inter-Affiliate Code of Conduct<br>dated May 22, 2003 |

| | |
|---|---|
| Decision 2003-061 | AltaLink Management Ltd., and TransAlta Utilities Corporation<br>Transmission Tariffs for May 1, 2002 to April 30, 2004 and TransAlta Utilities Corporation Transmission Tariffs for January 1, 2002 to April 30, 2002<br>dated August 3, 2003 |
| Decision 2003-072 | ATCO Gas<br>2003/2004 General Rate Application<br>dated October 1, 2003 |
| Decision 2003-098 | ATCO Electric Ltd., ATCO Gas North and ATCO Gas South, Both Operating Divisions of ATCO Gas and Pipelines Ltd.<br>Transfer of Certain Retail Assets to Direct Energy Marketing Limited and Proposed Arrangements with Direct Energy Regulated Services to Perform Certain Regulated Retail Functions<br>dated December 4, 2003 |

# APPENDIX 4 – DRT REVENUE REQUIREMENTS AND NON-ENERGY RATES

## North and South

**Schedule 1 – DRT Energy Revenue Requirements ($000s)**

| | Requested | | Board Approved |
|---|---|---|---|
| **Categories** | **5 month test period** | **12 month test period** | **12 month test period** |
| Procurement and Portfolio Management | 309 | 770 | 693 |
| Credit Charges | 1,242 | 2,964 | Update Monthly |
| Working Capital | -193 | -458 | -389 |
| Bad Debts | 886 | 2,067 | 2,067 |
| Penalty Revenue | -2,029 | -4,737 | -4,737 |
| **Total** | $215 | $605 | |

**Schedule 2 – DRT Non-Energy Revenue Requirements ($000s)**

| | | Requested | | Board Approved |
|---|---|---|---|---|
| | **Categories** | **5 month** | **12 month** | **12 month** |
| 1 | Customer Care Costs | 20,380 | 47,692 | 42,923 |
| 2 | Amortization of Integration Costs - Capital | 503 | 1,201 | 1,201 |
| 3 | Amortization of Integration Costs - Operating | 1,028 | 2,451 | 0 |
| 4 | Working Capital | 2,173 | 3,260 | 2,700 |
| 5 | Credit Charges | 63 | 148 | 148 |
| 6 | Amortization of Hearing Costs | 148 | 352 | 500 |
| 7 | Other Operating Costs | | | |
| | 7.1 Staff Salaries | 914 | 2,280 | 2,052 |
| | 7.2 Customer Education & Energy Awareness | 1,148 | 2,754 | 1,466 |
| | 7.3 Information Systems | 31 | 75 | 75 |
| | 7.4 Other Administration Costs | 179 | 379 | 379 |
| | 7.5 Interest on Security Deposits | 122 | 292 | 292 |
| | 7.6 Corporate Costs | 1,247 | 2,560 | 2,457 |
| 8 | Bad Debts | 421 | 981 | 981 |
| 9 | Penalty Revenue | -964 | -2,249 | -2,249 |
| | **Total Non-Energy Revenue Requirement** | 27,394 | 62,175 | 52,923 |

| Schedule 3 – Non-Energy DRT | | | | | | |
|---|---|---|---|---|---|---|
| | Requested Rates | | | | Board Approved Rates | |
| DRT Rate Class | 5 month test period | | 12 month test period | | 12 month test period | |
| | Customer Charge $/month | Variable Charge $/GJ | Customer Charges $/month | Variable Charges $/GJ | Customer Charges $/month | Variable Charges $/GJ |
| General Service (G1) | 6.27 | 0.028 | 6.09 | 0.017 | 5.19 | 0.014 |
| Large Use Service (G3) | 6.27 | 0.028 | 6.09 | 0.017 | 5.19 | 0.014 |
| Irrigation Pumping (G5) | 6.27 | 0.028 | 6.09 | 0.017 | 5.19 | 0.014 |

# APPENDIX 5 – RRT REVENUE REQUIREMENTS AND NON-ENERGY RATES

**Schedule 1 – RRT Non-Energy Revenue Requirements ($000s)**

| Categories | | Requested | | Board Approved |
|---|---|---|---|---|
| | | 5 month | 12 month | 12 month |
| 1 | Customer Care Costs | 4,034 | 9,533 | 8,579 |
| 2 | Amortization of Integration Costs - Capital | 272 | 648 | 648 |
| 3 | Amortization of Integration Costs - Operating | 253 | 603 | 0 |
| 4 | Working Capital | 298 | 603 | 494 |
| 5 | Credit Charges | 12 | 29 | 29 |
| 6 | Amortization of Hearing Costs | 148 | 352 | 500 |
| 7 | Other Operating Costs | | | |
| | 7.1 Staff Salaries | 468 | 1,166 | 1,049 |
| | 7.2 Customer Education & Energy Awareness | 227 | 546 | 289 |
| | 7.3 Information Systems | 67 | 160 | 160 |
| | 7.4 Other Administration Costs | 36 | 75 | 75 |
| | 7.5 Interest on Security Deposits | 17 | 40 | 40 |
| | 7.6 Corporate Costs | 247 | 508 | 487 |
| 8 | Bad Debts | 383 | 857 | 857 |
| 9 | Penalty Revenue | -422 | -942 | -942 |
| | **Total Non-Energy Revenue Requirement** | **6,040** | **14,179** | **12,267** |

| Schedule 2 – Non-Energy RRT | | | | | | |
|---|---|---|---|---|---|---|
| | Requested Rates | | | | Board Approved Rates | |
| RRT Rate Class | 5 month test period | | 12 month test period | | 12 month test period | |
| | Customer Charges $/month | Variable Charges $/kWh | Customer Charges $/month | Variable Charges $/kWh | Customer Charges $/month | Variable Charges $/kWh |
| Residential (E1) | 7.26 | 0.00047 | 7.12 | 0.00038 | 6.18 | 0.00031 |
| Small General (E2) | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |
| Large General (E3) | 5.40 | 0.00047 | 5.40 | 0.00038 | 4.62 | 0.00031 |
| Oilfield (E4) | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |
| Farm (E5) | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |
| Lighting (E6)* | 6.19 | 0.00047 | 6.13 | 0.00038 | 5.28 | 0.00031 |
| Irrigation (E7)** | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |

* The customer charge for rate E6 is per fixture

** The customer charge for rate E7 applies from April to October

# APPENDIX 6 – NORTH GAS DRT RATE SCHEDULES

"App 6 - North Gas
DRT Rate Schedules.

(Consists of 5 pages)

# APPENDIX 6

## DIRECT ENERGY REGULATED SERVICES

## RATE SCHEDULES

## NORTH GAS DRT SERVICE

Approved by Decision 2003-106
Effective ____________, 2004
Rate G1 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE G1 – GENERAL SERVICE

Available to all customers eligible for ATCO Gas and Pipelines Ltd. North (AGPLN) Rate No. 1 – General Sales Service Rate.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$5.19 per Month** |
| plus | |
| AGPLN Delivery Charge – Fixed including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.014 per GJ** |
| plus | |
| DERS Gas Cost Flow-Through Rate | **Rider "F"** |
| plus | |
| AGPLN Delivery Charge – Variable including Riders | |

| | |
|---|---|
| **Minimum Monthly Charge:** | **Fixed Charges** |

Approved by Decision 2003-106
Effective ____________, 2004
Rate G3 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE G3 – LARGE USE SERVICE

Available to all customers eligible for ATCO Gas and Pipelines Ltd. North (AGPLN) Rate No. 3 General Sales Service – Large Use.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$5.19 per Month** |
| plus | |
| AGPLN Delivery Charge – Fixed including Riders | |
| plus | |
| AGPLN Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.014 per GJ** |
| plus | |
| DERS Gas Cost Flow-Through Rate | **Rider "F"** |
| plus | |
| AGPLN Delivery Charge – Variable including Riders | |

| | |
|---|---|
| **Minimum Monthly Charge:** | **Fixed Charges** |

Approved by Decision 2003-106
Effective ____________, 2004
Rider "F" Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# Rider "F" GAS COST FLOW-THROUGH

To be applied to all energy sold to customers served under Rates G1 and G3.

**Gas Cost Flow-Through Rate:**

For customers served by ATCO Gas and Pipelines Ltd. North:

For the Period January 1, 2004 to January 31, 2004 **$_.___ per GJ**

Approved by Decision 2003-106
Effective ____________, 2004
General Conditions Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# GENERAL CONDITIONS

## 1. Approval of the Alberta Energy and Utilities Board (AEUB)

All Rates and Riders of DERS are subject to approval by the AEUB.

## 2. Terms and Conditions of Service

Service under all DERS's Rates and Riders are subject to the Terms and Conditions of Default Rate Service of DERS as approved by the AEUB.

## 3. Other ATCO Gas and Pipelines Ltd. (AGPL) Charges

In addition to the AGPL charges specifically identified in these Rate Schedules, DERS's Rates G1 and G3 will include, as applicable, all AGPL charges under Riders A, B, G, H and I, as well as any other charges or riders levied by AGPL and approved by the AEUB.

## APPENDIX 7 – SOUTH GAS DRT RATE SCHEDULES

"App 7 - South Gas
DRT Rate Schedules.

(Consists of 6 pages)

# APPENDIX 7

## DIRECT ENERGY REGULATED SERVICES

## RATE SCHEDULES

## SOUTH GAS DRT SERVICE

Approved by Decision 2003-106
Effective ____________, 2004
Rate G1 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE G1 – GENERAL SERVICE

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Rate No. 1 – General Sales Service Rate.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$5.19 per Month** |
| plus | |
| AGPLS Delivery Charge – Fixed including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.014 per GJ** |
| plus | |
| DERS Gas Cost Flow-Through Rate | **Rider "F"** |
| plus | |
| AGPLS Delivery Charge – Variable including Riders | |

**Minimum Monthly Charge:** **Fixed Charges**

Approved by Decision 2003-106
Effective ____________, 2004
Rate G3 Page 1 of 1

## DIRECT ENERGY REGULATED SERVICES
## (DERS)
## RATE G3 – LARGE USE SERVICE

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Rate No. 3 – Large Use Sales Service.

**CHARGES:**

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$5.19 per Month** |
| plus | |
| AGPLS Delivery Charge – Fixed including Riders | |
| plus | |
| AGPLS Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.014 per GJ** |
| plus | |
| DERS Gas Cost Flow-Through Rate | **Rider "F"** |
| plus | |
| AGPLS Delivery Charge – Variable including Riders | |

**Minimum Monthly Charge:** **Fixed Charges**

Approved by Decision 2003-106
Effective ____________, 2004
Rate G5 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE G5 – IRRIGATION PUMPING SERVICE

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Rate No. 5 – Optional Irrigation Pumping Service Rate.

## CHARGES:

| | |
|---|---|
| **Fixed Charges:** | |
| DERS Customer Charge | **$5.19 per Month** |
| plus | |
| AGPLS Delivery Charge – Fixed including Riders | |
| **Variable Charges:** | |
| DERS Variable Charge | **$0.014 per GJ** |
| plus | |
| DERS Gas Cost Flow-Through Rate | **Rider "F"** |
| plus | |
| AGPLS Delivery Charge – Variable including Riders | |
| **Minimum Monthly Charge:** | **Fixed Charges** |

Approved by Decision 2003-106
Effective ____________, 2004
Rider "F" Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# Rider "F" GAS COST FLOW-THROUGH

To be applied to all energy sold to customers served under Rates G1, G3 and G5.

**Gas Cost Flow-Through Rate:**

For customers served by ATCO Gas and Pipelines Ltd. South:

For the Period January 1, 2004 to January 31, 2004 **$_.__ per GJ**

Approved by Decision 2003-106
Effective ____________, 2004
General Conditions Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# GENERAL CONDITIONS

## 1. Approval of the Alberta Energy and Utilities Board (AEUB)

All Rates and Riders of DERS are subject to approval by the AEUB.

## 2. Terms and Conditions of Service

Service under all DERS's Rates and Riders are subject to the Terms and Conditions of Default Rate Service of DERS as approved by the AEUB.

## 3. Other ATCO Gas and Pipelines Ltd. (AGPL) Charges

In addition to the AGPL charges specifically identified in these Rate Schedules, DERS's Rates G1, G3 and G5 will include, as applicable, all AGPL charges under Riders A, B, G, H and I, as well as any other charges or riders levied by AGPL and approved by the AEUB.

## APPENDIX 8 – RRT RATE SCHEDULES

"App 8 - Electricity
RRT Rate Schedules.

(Consists of 10 pages)

# APPENDIX 8

## DIRECT ENERGY REGULATED SERVICES

## RATE SCHEDULES

## ELECTRICITY RRT SERVICE

Approved by Decision 2003-106
Effective ____________, 2004
Rate E1 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE E1 – RESIDENTIAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D11 – Standard Residential Service.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$6.18 per Month** |
| plus | |
| AE Delivery Charge – Fixed including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.00031 per kWh** |
| plus | |
| DERS Pool Price Flow-Through Rate | **Rider "P"** |
| plus | |
| AE Delivery Charge – Variable including Riders | |

**Minimum Monthly Charge:** **Fixed Charges**

Approved by Decision 2003-106
Effective ____________, 2004
Rate E2 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE E2 – SMALL GENERAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D21 Standard Small General Service and Price Schedule D22 Small General Service – Energy Only

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$6.27 per Month** |
| plus | |
| AE Delivery Charge – Fixed including Riders | |
| plus | |
| AE Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.00031 per kWh** |
| plus | |
| DERS Pool Price Flow-Through Rate | **Rider "P"** |
| plus | |
| AE Delivery Charge – Variable including Riders | |

**Minimum Monthly Charge:** **Fixed Charges**

Approved by Decision 2003-106
Effective ____________, 2004
Rate E3 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE E3 – LARGE GENERAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D31 Large General Service/Industrial, Price Schedule T31 Large General Service/Industrial Transmission Connected, and Price Schedule D32 Generator Interconnection and Standby Power.

## CHARGES:

**Fixed Charges:**

| | | |
|---|---|---|
| | DERS Customer Charge | **$4.62 per Month** |
| plus | | |
| | AE Delivery Charge – Fixed including Riders | |
| plus | | |
| | AE Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | | |
|---|---|---|
| | DERS Variable Charge | **$0.00031 per kWh** |
| plus | | |
| | DERS Pool Price Flow-Through Rate | **Rider "P"** |
| plus | | |
| | AE Delivery Charge – Variable including Riders | |

| | |
|---|---|
| **Minimum Monthly Charge:** | **Fixed Charges** |

Approved by Decision 2003-106
Effective ____________, 2004
Rate E4 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE E4 – OILFIELD SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D41 Small Oilfield and Pumping Power.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$6.27 per Month** |
| plus | |
| AE Delivery Charge – Fixed including Riders | |
| plus | |
| AE Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.00031 per kWh** |
| plus | |
| DERS Pool Price Flow-Through Rate | **Rider "P"** |
| plus | |
| AE Delivery Charge – Variable including Riders | |

**Minimum Monthly Charge:** **Fixed Charges**

Approved by Decision 2003-106
Effective ____________, 2004
Rate E5 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE E5 – FARM SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D56 Farm Service.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$6.27 per Month** |
| plus | |
| AE Delivery Charge – Fixed including Riders | |
| plus | |
| AE Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.00031 per kWh** |
| plus | |
| DERS Pool Price Flow-Through Rate | **Rider "P"** |
| plus | |
| AE Delivery Charge – Variable including Riders | |

**Minimum Monthly Charge:** **Fixed Charges**

Approved by Decision 2003-106
Effective ____________, 2004
Rate E6 Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# RATE E6 – LIGHTING SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D61 Street Lighting Service and Price Schedule D63 Private Lighting Service.

## CHARGES:

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge* | **$5.28 per Month** |
| plus | |
| AE Delivery Charge – Fixed including Riders | |
| plus | |
| AE Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.00031 per kWh** |
| plus | |
| DERS Pool Price Flow-Through Rate | **Rider "P"** |

| | |
|---|---|
| **Minimum Monthly Charge:** | **Fixed Charges** |

- The Customer Charge applies per Fixture

Approved by Decision 2003-106
Effective ____________, 2004
Rate E7 Page 1 of 1

## DIRECT ENERGY REGULATED SERVICES
## (DERS)
## RATE E7 – IRRIGATION PUMPING SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D25 Irrigation Pumping Service.

**CHARGES:**

**Fixed Charges:**

| | |
|---|---|
| DERS Customer Charge | **$6.27 per Month** |
| plus | |
| AE Delivery Charge – Fixed including Riders | |
| plus | |
| AE Delivery Charge – Demand including Riders | |

**Variable Charges:**

| | |
|---|---|
| DERS Variable Charge | **$0.00031 per kWh** |
| plus | |
| DERS Pool Price Flow-Through Rate | **Rider "P"** |
| plus | |
| AE Delivery Charge – Variable including Riders | |

| | |
|---|---|
| **Minimum Monthly Charge:** | **Fixed Charges** |

Approved by Decision 2003-106
Effective ____________, 2004
Rider "P" Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# Rider "P" POOL PRICE FLOW-THROUGH

To be applied to all energy sold to customers served under Rates E1, E2, E3, E4, E5, E6 and E7.

**Pool Price Flow-Through Rate:**

The Pool Price Flow-Through Rate shall be calculated as:

> The sum, for each Rate class, of the product of the hourly pool price multiplied by the hourly energy purchases for that Rate class, for each hour of the billing period, divided by:
>
> The sum, for each Rate class, of the energy sales to that Rate class for each hour of the billing period.

Approved by Decision 2003-106
Effective ____________, 2004
General Conditions Page 1 of 1

# DIRECT ENERGY REGULATED SERVICES
# (DERS)
# GENERAL CONDITIONS

## 1. Approval of the Alberta Energy and Utilities Board (AEUB)

All Rates and Riders of DERS are subject to approval by the AEUB.

## 2. Terms and Conditions of Service

Service under all DERS's Rates and Riders are subject to the Terms and Conditions of Regulated Rate Service of DERS as approved by the AEUB.

## 3. Other ATCO Electric Ltd. (AE) Charges

In addition to the AE charges specifically identified in these Rate Schedules, DERS's Rates E1, E2, E3, E4, E5, E6 and E7 will include, as applicable, all AE charges under Riders A-1, E, and J, as well as any Power Factor Corrections and Price Options, or other Charges or Riders levied by AE and approved by the AEUB.

# APPENDIX 9 – DRT REVENUE REQUIREMENTS AND NON-ENERGY RATES SPREADSHEET

"App 9 - DRT
Schedules.xls"

(Consists of 6 pages)

## Schedule 1 - DRT Energy Revenue Requirements ($000s)

| | Requested | | Board Approved |
|---|---|---|---|
| **Categories** | **5 month test period** | **12 month test period** | **12 month test period** |
| Procurement and Portfolio Management | 309 | 770 | 693 |
| Credit Charges | 1,242 | 2,964 | Update Monthly |
| Working Capital | -193 | -458 | -389 |
| Bad Debts | 886 | 2,067 | 2,067 |
| Penalty Revenue | -2,029 | -4,737 | -4,737 |
| **Total** | **$215** | **$605** | |

### Schedule 2 - DRT Non-Energy Revenue Requirements ($000s)

| | | Requested | | Board Approved |
|---|---|---|---|---|
| | **Categories** | **5 month** | **12 month** | **12 month** |
| 1 | Customer Care Costs | 20,380 | 47,692 | 42,923 |
| 2 | Amortization of Integration Costs - Capital | 503 | 1,201 | 1,201 |
| 3 | Amortization of Integration Costs - Operating | 1,028 | 2,451 | 0 |
| 4 | Working Capital | 2,173 | 3,260 | 2,700 |
| 5 | Credit Charges | 63 | 148 | 148 |
| 6 | Amortization of Hearing Costs | 148 | 352 | 500 |
| 7 | Other Operating Costs | | | |
| | 7.1 Staff Salaries | 914 | 2,280 | 2,052 |
| | 7.2 Customer Education & Energy Awareness | 1,148 | 2,754 | 1,466 |
| | 7.3 Information Systems | 31 | 75 | 75 |
| | 7.4 Other Administration Costs | 179 | 379 | 379 |
| | 7.5 Interest on Security Deposits | 122 | 292 | 292 |
| | 7.6 Corporate Costs | 1,247 | 2,560 | 2,457 |
| 8 | Bad Debts | 421 | 981 | 981 |
| 9 | Penalty Revenue | -964 | -2,249 | -2,249 |
| | **Total Non-Energy Revenue Requirement** | **27,394** | **62,175** | **52,923** |

## Schedule 3 - Non-Energy DRT

|  | Requested Rates |  |  |  | Board Approved Rates |  |
|---|---|---|---|---|---|---|
| DRT Rate Class | 5 month test period |  | 12 month test period |  | 12 month test period |  |
|  | Customer Charge $/month | Variable Charge $/GJ | Customer Charges $/month | Variable Charges $/GJ | Customer Charges $/month | Variable Charges $/GJ |
| General Service (G1) | 6.27 | 0.028 | 6.09 | 0.017 | 5.19 | 0.014 |
| Large Use Service (G3) | 6.27 | 0.028 | 6.09 | 0.017 | 5.19 | 0.014 |
| Irrigation Pumping (G5) | 6.27 | 0.028 | 6.09 | 0.017 | 5.19 | 0.014 |

## Schedule 4 - DRT Working Capital

| | | Requested | | | | | | Board Approved | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 5 month test period | | | 12 month test period | | | 12 month test period | | |
| | Description | Percent | Total | Working Capital | Percent | Total | Working Capital | Percent | Total | Working Capital |
| | **Cash Expense** | | | | | | | | | |
| 1 | Gas Cost | -0.44% | $434,452,784 | -$1,930,187 | -0.45% | $1,015,646,242 | -$4,579,906 | -0.45% | $1,015,646,242 | -$4,579,906 |
| 2 | ATCO Gas' Distribution Service Charges | 1.74% | $132,109,203 | $2,304,990 | 1.74% | $319,503,512 | $5,553,286 | 1.74% | $319,503,512 | $5,553,309 |
| 3 | Municipal Franchise Fee | 1.74% | $42,846,737 | $747,573 | 1.74% | $100,607,387 | $1,748,663 | 1.74% | $100,607,387 | $1,748,663 |
| 4 | Salaries | 8.51% | $908,944 | $77,393 | 8.51% | $2,279,631 | $193,950 | 8.51% | $2,051,668 | $174,555 |
| 5 | Customer Care Costs | -1.81% | $20,258,210 | -$367,513 | -1.82% | $47,691,806 | -$868,372 | -1.82% | $42,922,626 | -$781,534 |
| 6 | Insurance | 14.73% | $17,391 | $2,562 | 14.73% | $50,068 | $7,374 | 14.73% | $50,068 | $7,374 |
| 7 | Amortization of Integration Costs Capital | 10.57% | $500,235 | $52,872 | 10.56% | $1,200,563 | $126,813 | 10.56% | $1,200,563 | $126,813 |
| 8 | GST | | | $847,375 | | | $1,973,129 | | | $1,973,129 |
| | **Total Working Capital Requirements - Cash Expenses** | | | **$1,735,066** | | | **$4,154,961** | | | **$4,222,403** |
| | | | | | | | | | | |
| | **Adjustments (Average Balances)** | | | | | | | | | |
| 9 | Payment Equalization Plan | | | $45,873,400 | | | $29,229,667 | | | $29,229,667 |
| 10 | Integration Capital Costs | | | $5,752,697 | | | $4,902,298 | | | $5,402,533 |
| 11 | Hearing Costs | | | $426,471 | | | $176,471 | | | $0 |
| 12 | Integration Operating Costs | | | $2,967,150 | | | $1,227,786 | | | $0 |
| 13 | Customer Deposits | | | -$11,667,071 | | | -$11,667,071 | | | -$11,667,071 |
| | **Total Working Capital Requirements - Adjustments** | | | **$43,352,647** | | | **$23,869,151** | | | **$22,965,128** |

| | 5 month test period | 12 month test period | 12 month test period |
|---|---|---|---|
| **Cost of Capital** | **10%** | **10%** | **8.5%** |
| **Total Working Capital Cost** | **$1,979,867** | **$2,802,411** | **$2,310,940** |

Note: Total working capital for 5 month period = cash expenses x 10% + adjustments x 10% x 5/12

| | | | |
|---|---|---|---|
| **GCRR Working Capital Cost** | **-$193,019** | **-$457,991** | **-$389,292** |
| **Retail Working Capital Cost** | **$2,172,886** | **$3,260,402** | **$2,700,232** |

# Schedule 5 - DRT Cost Allocators by Rate Class

### 5 month test period DRT Cost Allocators by Rate Class

| CUSTOMERS | Rate | Customers Months | Percentage | No. Bills after Consolidated Billing (#/year) | Percentage | Regulated Sales (TJ/year) | Percentage |
|---|---|---|---|---|---|---|---|
| Residential | 1A1A | 3,637,226 | 90.38% | 3,637,226 | 90.38% | 40,576 | 51.64% |
| Small Apartments | 2A1A | 33,822 | 0.84% | 33,822 | 0.84% | 4,473 | 5.69% |
| Large Apartment | 2A3A | 1,290 | 0.03% | 1,290 | 0.03% | 1,500 | 1.91% |
| Small Commercial | 3A1A | 341,029 | 8.47% | 341,029 | 8.47% | 20,556 | 26.16% |
| Large Commercial | 3A3A | 6,303 | 0.16% | 6,303 | 0.16% | 9,681 | 12.32% |
| Small Industrial | 6A1A | 625 | 0.02% | 625 | 0.02% | 152 | 0.19% |
| Large Industrial | 6A3A | 675 | 0.02% | 675 | 0.02% | 1,237 | 1.57% |
| Irrigation | 7A5A | 3,405 | 0.08% | 3,405 | 0.08% | 401 | 0.51% |
| Total | | 4,024,375 | 100.00% | 4,024,375 | 100.00% | 78,576 | 100.00% |

### Aggregation into Regulated Rate Classes

| RATE CLASS | Rate | Customers | Percentage | No. Bills after Consolidated Billing (#/year) | Percentage | Regulated Sales (TJ/year) | Percentage |
|---|---|---|---|---|---|---|---|
| General Service | 1A1A 2A1A<br>3A1A 6A1A | 4,012,702 | 99.71% | 4,012,702 | 99.71% | 65,757 | 83.69% |
| Large Use Service | 2A3A 3A3A<br>6A3A | 8,268 | 0.21% | 8,268 | 0.21% | 12,418 | 15.80% |
| Irrigation Pumping | 7A5A | 3,405 | 0.08% | 3,405 | 0.08% | 401 | 0.51% |
| | | 4,024,375 | 100.00% | 4,024,375 | 100.00% | 78,576 | 100.00% |

### 12 month test period DRT Cost Allocators by Rate Class

| CUSTOMERS | Rate | Customers Months | Percentage | No. Bills after Consolidated Billing (#/year) | Percentage | Regulated Sales (TJ/year) | Percentage |
|---|---|---|---|---|---|---|---|
| Residential | 1A1A | 8,736,880 | 90.29% | 8,736,880 | 90.29% | 97,534 | 50.82% |
| Small Apartments | 2A1A | 81,654 | 0.84% | 81,654 | 0.84% | 10,542 | 5.49% |
| Large Apartment | 2A3A | 3,096 | 0.03% | 3,096 | 0.03% | 3,644 | 1.90% |
| Small Commercial | 3A1A | 828,510 | 8.56% | 828,510 | 8.56% | 51,050 | 26.60% |
| Large Commercial | 3A3A | 15,222 | 0.16% | 15,222 | 0.16% | 24,330 | 12.68% |
| Small Industrial | 6A1A | 1,500 | 0.02% | 1,500 | 0.02% | 360 | 0.19% |
| Large Industrial | 6A3A | 1,620 | 0.02% | 1,620 | 0.02% | 3,690 | 1.92% |
| Irrigation | 7A5A | 8,311 | 0.09% | 8,311 | 0.09% | 787 | 0.41% |
| Total | | 9,676,793 | 100.00% | 9,676,793 | 100.00% | 191,937 | 100.00% |

### Aggregation into Regulated Rate Classes

| RATE CLASS | Rate | Customers | Percentage | No. Bills after Consolidated Billing (#/year) | Percentage | Regulated Sales (TJ/year) | Percentage |
|---|---|---|---|---|---|---|---|
| General Service | 1A1A 2A1A<br>3A1A 6A1A | 9,648,544 | 99.71% | 9,648,544 | 99.71% | 159,486 | 83.09% |
| Large Use Service | 2A3A 3A3A<br>6A3A | 19,938 | 0.21% | 19,938 | 0.21% | 31,664 | 16.50% |
| Irrigation Pumping | 7A5A | 8,311 | 0.09% | 8,311 | 0.09% | 787 | 0.41% |
| | | 9,676,793 | 100.00% | 9,676,793 | 100.00% | 191,937 | 100.00% |

# Schedule 6 - DRT Cost Allocation to Various Rate Classes

**5 month test period Allocated DRT Costs by Rate Class**

| | | Fixed Costs ($000) | | | | | | | | | | | | | | Variable Costs ($000) | | Total Regulated Costs ($000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | | Customer Care | Credit Charges | Bad Debt | Penalty Revenue | Customer Education and Energy Awareness | Salaries | Corporate | IS | Amortized Integration Capital Costs | Other Admin Costs | Interest on Security Deposits | Amortized Hearing Costs | Amortized Integration Operating Costs | **Total Fixed Costs** | Working Capital | **Total Variable Costs** | |
| General Service | 1 | 20,321.2 | 62.5 | 419.3 | -961.0 | 1,144.5 | 911.8 | 1,243.5 | 31.4 | 501.8 | 178.9 | 121.9 | 147.3 | 1,024.5 | **25,147.6** | 1,818.4 | **1,818.4** | **26,965.9** |
| Large Use Service | 3 | 41.9 | 0.1 | 0.9 | -2.0 | 2.4 | 1.9 | 2.6 | 0.1 | 1.0 | 0.4 | 0.3 | 0.3 | 2.1 | **51.8** | 343.4 | **343.4** | **395.2** |
| Irrigation Pumping | 5 | 17.2 | 0.1 | 0.4 | -0.8 | 1.0 | 0.8 | 1.1 | 0.0 | 0.4 | 0.2 | 0.1 | 0.1 | 0.9 | **21.3** | 11.1 | **11.1** | **32.4** |
| **Total** | | **20,380.3** | **62.7** | **420.5** | **-963.8** | **1,147.9** | **914.4** | **1,247.1** | **31.4** | **503.2** | **179.5** | **122.3** | **147.7** | **1,027.5** | **25,220.7** | **2,172.9** | **2,172.9** | **27,393.6** |

**12 month test period Allocated DRT Costs by Rate Class**

| | | Fixed Costs ($000) | | | | | | | | | | | | | | Variable Costs ($000) | | Total Regulated Costs ($000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | | Customer Care | Credit Charges | Bad Debt | Penalty Revenue | Customer Education and Energy Awareness | Salaries | Corporate | IS | Amortized Integration Capital Costs | Other Admin Costs | Interest on Security Deposits | Amortized Hearing Costs | Amortized Integration Operating Costs | **Total Fixed Costs** | Working Capital | **Total Variable Costs** | |
| General Service | 1 | 47,552.6 | 147.2 | 978.6 | -2,242.9 | 2,745.7 | 2,273.0 | 2,552.6 | 74.8 | 1,197.1 | 378.0 | 290.8 | 351.3 | 2,444.1 | **58,742.7** | 2,709.2 | **2,709.2** | **61,451.8** |
| Large Use Service | 3 | 98.3 | 0.3 | 2.0 | -4.6 | 5.7 | 4.7 | 5.3 | 0.2 | 2.5 | 0.8 | 0.6 | 0.7 | 5.1 | **121.4** | 537.9 | **537.9** | **659.3** |
| Irrigation Pumping | 5 | 41.0 | 0.1 | 0.8 | -1.9 | 2.4 | 2.0 | 2.2 | 0.1 | 1.0 | 0.3 | 0.3 | 0.3 | 2.1 | **50.6** | 13.4 | **13.4** | **64.0** |
| **Total** | | **47,691.8** | **147.6** | **981.5** | **-2,249.5** | **2,753.7** | **2,279.6** | **2,560.0** | **75.0** | **1,200.6** | **379.1** | **291.7** | **352.3** | **2,451.2** | **58,914.7** | **3,260.4** | **3,260.4** | **62,175.1** |

*Notes*

**(1) Customer Care, Credit Charges, Bad Debt and Penalty Revenue are allocated based on number of DRT customers after billing consolidation**

**(2) Customer Education, Salaries, Corporate, IS, Amortized Integration Capital and Operating Costs, Other Admin, Amortized Hearing Costs, Interest on Security Deposits are allocated based on number of regulated customers**

**(3) Amortized Integration Operating and Amortized Hearing costs are amortized over the 5 and 12 month test periods**

**12 month test period Allocated DRT Costs by Rate Class**

**Board Approved**

| | | Fixed Costs ($000) | | | | | | | | | | | | | | Variable Costs ($000) | | Total Regulated Costs ($000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | | Customer Care | Credit Charges | Bad Debt | Penalty Revenue | Customer Education and Energy Awareness | Salaries | Corporate | IS | Amortized Integration Capital Costs | Other Admin Costs | Interest on Security Deposits | Amortized Hearing Costs | Amortized Integration Operating Costs | **Total Fixed Costs** | Working Capital | **Total Variable Costs** | |
| General Service | 1 | 42,797.3 | 147.2 | 978.6 | -2,242.9 | 1,461.7 | 2,045.7 | 2,449.7 | 74.8 | 1,197.1 | 378.0 | 290.8 | 498.5 | 0.0 | **50,076.5** | 2,243.7 | **2,243.7** | **52,320.2** |
| Large Use Service | 3 | 88.4 | 0.3 | 2.0 | -4.6 | 3.0 | 4.2 | 5.1 | 0.2 | 2.5 | 0.8 | 0.6 | 1.0 | 0.0 | **103.5** | 445.5 | **445.5** | **548.9** |
| Irrigation Pumping | 5 | 36.9 | 0.1 | 0.8 | -1.9 | 1.3 | 1.8 | 2.1 | 0.1 | 1.0 | 0.3 | 0.3 | 0.4 | 0.0 | **43.1** | 11.1 | **11.1** | **54.2** |
| **Total** | | **42,922.6** | **147.6** | **981.5** | **-2,249.5** | **1,466.0** | **2,051.7** | **2,456.9** | **75.0** | **1,200.6** | **379.1** | **291.7** | **500.0** | **0.0** | **50,223.1** | **2,700.2** | **2,700.2** | **52,923.3** |

# APPENDIX 10 – RRT REVENUE REQUIREMENTS AND NON-ENERGY RATES SPREADSHEET

"App 10 - RRT Schedules.xls"

(Consists of 5 pages)

### Schedule 1 - RRT Non-Energy Revenue Requirements ($000s)

| | | Requested | | Board Approved |
|---|---|---|---|---|
| | **Categories** | **5 month** | **12 month** | **12 month** |
| 1 | Customer Care Costs | 4,034 | 9,533 | 8,579 |
| 2 | Amortization of Integration Costs - Capital | 272 | 648 | 648 |
| 3 | Amortization of Integration Costs - Operating | 253 | 603 | 0 |
| 4 | Working Capital | 298 | 603 | 494 |
| 5 | Credit Charges | 12 | 29 | 29 |
| 6 | Amortization of Hearing Costs | 148 | 352 | 500 |
| 7 | Other Operating Costs | | | |
| | 7.1 Staff Salaries | 468 | 1,166 | 1,049 |
| | 7.2 Customer Education & Energy Awarenes | 227 | 546 | 289 |
| | 7.3 Information Systems | 67 | 160 | 160 |
| | 7.4 Other Administration Costs | 36 | 75 | 75 |
| | 7.5 Interest on Security Deposits | 17 | 40 | 40 |
| | 7.6 Corporate Costs | 247 | 508 | 487 |
| 8 | Bad Debt | 383 | 857 | 857 |
| 9 | Penalty Revenue | -422 | -942 | -942 |
| | **Total Non-Energy Revenue Requirement** | **6,040** | **14,179** | **12,267** |

### Schedule 2 - Non-Energy RRT

| | Requested Rates | | | | Board Approved Rates | |
|---|---|---|---|---|---|---|
| RRT Rate Class | 5 month test period | | 12 month test period | | 12 month test period | |
| | Customer Charges $/month | Variable Charges $/kWh | Customer Charges $/month | Variable Charges $/kWh | Customer Charges $/month | Variable Charges $/kWh |
| Residential (E1) | 7.26 | 0.00047 | 7.12 | 0.00038 | 6.18 | 0.00031 |
| Small General (E2) | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |
| Large General (E3) | 5.40 | 0.00047 | 5.40 | 0.00038 | 4.62 | 0.00031 |
| Oilfield (E4) | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |
| Farm (E5) | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |
| Lighting (E6)* | 6.19 | 0.00047 | 6.13 | 0.00038 | 5.28 | 0.00031 |
| Irrigation (E7)** | 7.37 | 0.00047 | 7.22 | 0.00038 | 6.27 | 0.00031 |

* The customer charge for rate E6 is per fixture

** The customer charge for rate E7 applies from April to October

## Schedule 3 - RRT Working Capital

| | | Requested | | | | | | Board Approved | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 5 month test period | | | 12 month test period | | | 12 month test period | | |
| | Description | Percent | Total | Working Capital | Percent | Total | Working Capital | Percent | Total | Working Capital |
| | **Cash Expense** | | | | | | | | | |
| 1 | Electricity Cost | -0.03% | $33,464,849 | -$9,642 | -0.03% | $68,409,064 | -$19,710 | -0.03% | $68,409,064 | -$19,710 |
| 2 | ATCO Electric's Distribution Service Charges | 3.20% | $43,729,798 | $1,399,933 | 3.20% | $105,800,449 | $3,387,016 | 3.20% | $105,800,449 | $3,387,016 |
| 3 | Municipal Franchise Fee | 3.20% | $2,823,202 | $90,380 | 3.20% | $6,367,055 | $203,830 | 3.20% | $6,367,055 | $203,830 |
| 4 | Salaries | 9.97% | $464,838 | $46,350 | 9.97% | $1,165,814 | $116,245 | 9.97% | $1,049,232 | $104,621 |
| 5 | Customer Care Costs | -0.36% | $4,010,212 | -$14,340 | -0.36% | $9,532,705 | -$34,087 | -0.36% | $8,579,434 | -$30,678 |
| 6 | Insurance | 16.19% | $3,442 | $557 | 16.19% | $9,932 | $1,608 | 16.19% | $9,932 | $1,608 |
| 7 | Amortization of Integration Costs - Capital | 12.03% | $269,908 | $32,459 | 12.03% | $647,779 | $77,902 | 12.03% | $647,779 | $77,902 |
| 8 | GST | | | $205,289 | | | $467,562 | | | $467,562 |
| | **Total Working Capital Requirements - Cash Expenses** | | | **$1,750,986** | | | **$4,200,367** | | | **$4,192,151** |
| | **Adjustments (Average Balances)** | | | | | | | | | |
| 9 | Payment Equalization Plan | | | $298,680 | | | $303,125 | | | $303,125 |
| 10 | Integration Capital Costs | | | $3,103,941 | | | $2,645,097 | | | $2,915,005 |
| 11 | Hearing Costs | | | $426,471 | | | $176,471 | | | |
| 12 | Integration Operating Costs | | | $730,298 | | | $302,192 | | | |
| 13 | Customer Deposits | | | -$1,600,000 | | | -$1,600,000 | | | -$1,600,000 |
| | **Total Working Capital Requirements - A djustments** | | | **$2,959,389** | | | **$1,826,885** | | | **$1,618,130** |

| | 5 month test period | 12 month test period | 12 month test period |
|---|---|---|---|
| **Cost of Capital** | 10% | 10% | 8.5% |
| **Working Capital Cost Total** | $298,407 | $602,725 | $493,874 |

# Schedule 4 - RRT Cost Allocators by Rate Class

## 5 month test period RRT Cost Allocators by Rate Class

| Rate Classes | | No. of RRT Customers Months | Percentage | No. of RRT Bills after Consolidated Billing (#/year) | Percentage | RRT Sales (kW.h/year) | Percentage |
|---|---|---|---|---|---|---|---|
| Residential | E1 | 569,721 | 71.48% | 558,327 | 72.22% | 318,543,406 | 49.69% |
| Small General | E2 | 85,655 | 10.75% | 85,655 | 11.08% | 172,405,115 | 26.89% |
| Large General | E3 | 2,184 | 0.27% | 1,398 | 0.18% | 34,564,159 | 5.39% |
| Oilfield | E4 | 2,540 | 0.32% | 2,540 | 0.33% | 8,412,320 | 1.31% |
| Farm | E5 | 81,951 | 10.28% | 81,951 | 10.60% | 102,695,684 | 16.02% |
| Lighting | E6 | 54,785 | 6.87% | 43,007 | 5.56% | 3,008,680 | 0.47% |
| Irrigation | E7 | 205 | 0.03% | 205 | 0.03% | 1,420,124 | 0.22% |
| **TOTAL** | | **797,042** | **100.00%** | **773,083** | **100.00%** | **641,049,488** | **100.00%** |

*** The above numbers are from August to December 2003**

## 12 month test period RRT Cost Allocators by Rate Class

| Rate Classes | | No. of RRT Customers Months | Percentage | No. of RRT Bills after Consolidated Billing (#/year) | Percentage | RRT Sales (kW.h/year) | Percentage |
|---|---|---|---|---|---|---|---|
| Residential | E1 | 1,387,302 | 72.27% | 1,359,556 | 72.99% | 813,194,314 | 51.86% |
| Small General | E2 | 202,854 | 10.57% | 202,854 | 10.89% | 414,696,167 | 26.45% |
| Large General | E3 | 3,599 | 0.19% | 2,303 | 0.12% | 56,343,872 | 3.59% |
| Oilfield | E4 | 2,500 | 0.13% | 2,500 | 0.13% | 8,402,562 | 0.54% |
| Farm | E5 | 193,525 | 10.08% | 193,525 | 10.39% | 264,987,776 | 16.90% |
| Lighting | E6 | 129,386 | 6.74% | 101,568 | 5.45% | 7,086,701 | 0.45% |
| Irrigation | E7 | 478 | 0.02% | 478 | 0.03% | 3,369,706 | 0.21% |
| **TOTAL** | | **1,919,645** | **100.00%** | **1,862,785** | **100.00%** | **1,568,081,098** | **100.00%** |

# Schedule 5 - RRT Cost Allocation to Various Rate Classes

**5 month test period Allocated RRT Costs by Rate Class**

| | | Fixed Costs ($000) | | | | | | | | | | | | | | Variable Costs ($000) | | Total RRT Costs ($000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | | Customer Care | Credit Charges | Bad Debt | Penalty Revenue | Customer Education and Energy Awareness | Salaries | Corporate | IS | Amortized Integration Capital Costs | Other Admin Costs | Interest on Security Deposits | Amortized Hearing Costs | Amortized Integration Operating Costs | Total Fixed Costs | Working Capital | Total Variable Costs | |
| Residential | E1 | 2,913.7 | 9.0 | 276.8 | -304.4 | 164.0 | 334.3 | 176.4 | 48.0 | 194.1 | 25.4 | 12.0 | 105.6 | 180.8 | 4,135.5 | 148.3 | 148.3 | 4,283.8 |
| Small General | E2 | 447.0 | 1.4 | 42.5 | -46.7 | 25.2 | 50.3 | 26.5 | 7.2 | 29.2 | 3.8 | 1.8 | 15.9 | 27.2 | 631.1 | 80.3 | 80.3 | 711.4 |
| Large General | E3 | 7.3 | 0.0 | 0.7 | -0.8 | 0.4 | 1.3 | 0.7 | 0.2 | 0.7 | 0.1 | 0.0 | 0.4 | 0.7 | 11.8 | 16.1 | 16.1 | 27.9 |
| Oilfield | E4 | 13.3 | 0.0 | 1.3 | -1.4 | 0.7 | 1.5 | 0.8 | 0.2 | 0.9 | 0.1 | 0.1 | 0.5 | 0.8 | 18.7 | 3.9 | 3.9 | 22.6 |
| Farm | E5 | 427.7 | 1.3 | 40.6 | -44.7 | 24.1 | 48.1 | 25.4 | 6.9 | 27.9 | 3.7 | 1.7 | 15.2 | 26.0 | 603.8 | 47.8 | 47.8 | 651.7 |
| Lighting | E6 | 224.4 | 0.7 | 21.3 | -23.4 | 12.6 | 32.1 | 17.0 | 4.6 | 18.7 | 2.4 | 1.2 | 10.2 | 17.4 | 339.1 | 1.4 | 1.4 | 340.5 |
| Irrigation | E7 | 1.1 | 0.0 | 0.1 | -0.1 | 0.1 | 0.1 | 0.1 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.1 | 1.5 | 0.7 | 0.7 | 2.2 |
| Total | | 4,034.4 | 12.4 | 383.2 | -421.5 | 227.1 | 467.6 | 246.8 | 67.2 | 271.5 | 35.5 | 16.8 | 147.7 | 252.9 | 5,741.7 | 298.4 | 298.4 | 6,040.1 |

**12 month test period Allocated RRT Costs by Rate Class**

| | | Fixed Costs ($000) | | | | | | | | | | | | | | Variable Costs ($000) | | Total RRT Costs ($000) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Rate Class | | Customer Care | Credit Charges | Bad Debt | Penalty Revenue | Customer Education and Energy Awareness | Salaries | Corporate | IS | Amortized Integration Capital Costs | Other Admin Costs | Interest on Security Deposits | Amortized Hearing Costs | Amortized Integration Operating Costs | Total Fixed Costs | Working Capital | Total Variable Costs | |
| Residential | E1 | 6,957.5 | 21.2 | 625.7 | -687.5 | 394.8 | 842.5 | 367.0 | 115.9 | 468.1 | 54.3 | 28.9 | 254.6 | 436.0 | 9,879.0 | 312.6 | 312.6 | 10,191.6 |
| Small General | E2 | 1,038.1 | 3.1 | 93.4 | -102.6 | 57.7 | 123.2 | 53.7 | 16.9 | 68.5 | 7.9 | 4.2 | 37.2 | 63.8 | 1,465.1 | 159.4 | 159.4 | 1,624.5 |
| Large General | E3 | 11.8 | 0.1 | 1.1 | -1.2 | 1.0 | 2.2 | 1.0 | 0.3 | 1.2 | 0.1 | 0.1 | 0.7 | 1.1 | 19.4 | 21.7 | 21.7 | 41.1 |
| Oilfield | E4 | 12.8 | 0.0 | 1.2 | -1.3 | 0.7 | 1.5 | 0.7 | 0.2 | 0.8 | 0.1 | 0.1 | 0.5 | 0.8 | 18.1 | 3.2 | 3.2 | 21.3 |
| Farm | E5 | 990.4 | 3.0 | 89.1 | -97.9 | 55.1 | 117.5 | 51.2 | 16.2 | 65.3 | 7.6 | 4.0 | 35.5 | 60.8 | 1,397.7 | 101.9 | 101.9 | 1,499.6 |
| Lighting | E6 | 519.8 | 2.0 | 46.7 | -51.4 | 36.8 | 78.6 | 34.2 | 10.8 | 43.7 | 5.1 | 2.7 | 23.7 | 40.7 | 793.4 | 2.7 | 2.7 | 796.1 |
| Irrigation | E7 | 2.4 | 0.0 | 0.2 | -0.2 | 0.1 | 0.3 | 0.1 | 0.0 | 0.2 | 0.0 | 0.0 | 0.1 | 0.2 | 3.5 | 1.3 | 1.3 | 4.7 |
| Total | | 9,532.7 | 29.3 | 857.2 | -941.9 | 546.3 | 1,165.8 | 507.8 | 160.3 | 647.8 | 75.2 | 40.0 | 352.3 | 603.3 | 13,576.2 | 602.7 | 602.7 | 14,178.9 |

Notes:
(1) Customer Care, Credit Charges, Bad Debt and Penalty Revenue are allocated based on number of RRT customers after billing consolidation
(2) Customer Education, Salaries, Corporate, IS, Amortized Integration Capital Costs, Other Admin, Amortized Hearing Costs, Interest on Security Deposits and Amortized Integration Operating costs are allocated based on number of regulated customers
(3) Amortized Integration Operating and Amortized Hearing costs are amortized over balance of the 5 and 12 month test period

**12 month test period Allocated RRT Costs by Rate Class**

| | | Board Approved | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Fixed Costs ($000) | | | | | | | | | | | | | | Variable Costs ($000) | | Total RRT Costs ($000) |
| Rate Class | | Customer Care | Credit Charges | Bad Debt | Penalty Revenue | Customer Education and Energy Awareness | Salaries | Corporate | IS | Amortized Integration Capital Costs | Other Admin Costs | Interest on Security Deposits | Amortized Hearing Costs | Amortized Integration Operating Costs | Total Fixed Costs | Working Capital | Total Variable Costs | |
| Residential | E1 | 6,261.7 | 21.4 | 625.7 | -687.5 | 208.9 | 758.3 | 352.2 | 115.9 | 468.1 | 54.3 | 28.9 | 361.3 | 0.0 | 8,569.2 | 256.1 | 256.1 | 8,825.3 |
| Small General | E2 | 934.3 | 3.2 | 93.4 | -102.6 | 30.5 | 110.9 | 51.5 | 16.9 | 68.5 | 7.9 | 4.2 | 52.8 | 0.0 | 1,271.6 | 130.6 | 130.6 | 1,402.2 |
| Large General | E3 | 10.6 | 0.0 | 1.1 | -1.2 | 0.5 | 2.0 | 0.9 | 0.3 | 1.2 | 0.1 | 0.1 | 0.9 | 0.0 | 16.6 | 17.7 | 17.7 | 34.4 |
| Oilfield | E4 | 11.5 | 0.0 | 1.2 | -1.3 | 0.4 | 1.4 | 0.6 | 0.2 | 0.8 | 0.1 | 0.1 | 0.7 | 0.0 | 15.7 | 2.6 | 2.6 | 18.3 |
| Farm | E5 | 891.3 | 3.0 | 89.1 | -97.9 | 29.1 | 105.8 | 49.1 | 16.2 | 65.3 | 7.6 | 4.0 | 50.4 | 0.0 | 1,213.1 | 83.5 | 83.5 | 1,296.6 |
| Lighting | E6 | 467.8 | 1.6 | 46.7 | -51.4 | 19.5 | 70.7 | 32.9 | 10.8 | 43.7 | 5.1 | 2.7 | 33.7 | 0.0 | 683.8 | 2.2 | 2.2 | 686.0 |
| Irrigation | E7 | 2.2 | 0.0 | 0.2 | -0.2 | 0.1 | 0.3 | 0.1 | 0.0 | 0.2 | 0.0 | 0.0 | 0.1 | 0.0 | 3.0 | 1.1 | 1.1 | 4.1 |
| Total | | 8,579.4 | 29.3 | 857.2 | -941.9 | 289.0 | 1,049.2 | 487.4 | 160.3 | 647.8 | 75.2 | 40.0 | 500.0 | 0.0 | 11,773.0 | 493.9 | 493.9 | 12,266.9 |